UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

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

PETITION OF THE NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION FOR APPROVAL OF PROPOSED RELIABILITY STANDARD EOP-011-1—EMERGENCY OPERATIONS

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TABLE OF CONTENTS

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Pursuant to Section 215(d)(1) of the Federal Power Act ("FPA")[1] and Section 39.5[2] of the Federal Energy Regulatory Commission's ("FERC" or "Commission") regulations, the North American Electric Reliability Corporation ("NERC")[3] hereby submits proposed Reliability Standard EOP-011-1 and the revised definition of "Energy Emergency" ("Definition") for Commission approval. NERC requests that the Commission approve proposed Reliability Standard EOP-011-1 (**Exhibit A**) and the Definition and find that the proposed Reliability Standard and Definition are just, reasonable, not unduly discriminatory or preferential, and in the public interest.[4] NERC also requests approval of the associated implementation plan (**Exhibit B**), Violation Risk Factors ("VRFs") and Violation Severity Levels ("VSLs") (**Exhibit E**), as detailed in this petition.

As required by Section 39.5(a)[5] of the Commission's regulations, this petition presents the technical basis and purpose of proposed Reliability Standard EOP-011-1, a demonstration

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1 16 U.S.C. § 824o (2006).

2 18 C.F.R. § 39.5 (2013).

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

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

5 18 C.F.R. § 39.5(a) (2013).

that the proposed Reliability Standard meets the criteria identified by the Commission in Order No. 672[6] (**Exhibit C**) and a summary of the development history (**Exhibit H**). Proposed Reliability Standard EOP-011-1 was approved by the NERC Board of Trustees on November 13, 2014.

I. EXECUTIVE SUMMARY

The Emergency Preparedness and Operations ("EOP") group of Reliability Standards currently consists of eight Reliability Standards that address preparation for emergencies, necessary actions during emergencies and system restoration and reporting following disturbances. The purpose of proposed Reliability Standard EOP-011-1 is to address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plans to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator Area.

Proposed Reliability Standard EOP-011-1 is a fundamentally important Reliability Standard that streamlines the requirements for Emergency operations of the Bulk Electric System. Attachment 1, which is incorporated into Requirements R2 and R6, provides the process and descriptions of the levels used by the Reliability Coordinator when communicating the condition of a Balancing Authority that is experiencing an Energy Emergency. There are three levels of Energy Emergency Alerts:

- **Energy Emergency Alert Level 1: All available generation resources in use.** This occurs when the Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.

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

- **Energy Emergency Alert Level 2: Load management procedures in effect.** This occurs when the Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority. An energy deficient Balancing Authority has implemented its Operating Plan to mitigated Emergencies. An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

- **Energy Emergency Alert Level 3: Firm Load interruption is imminent or in process.** This occurs when the energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

The proposed Reliability Standard consolidates requirements from three existing Reliability Standards; EOP-001-2.1b, EOP-003.1, and EOP-003-2, into a single Reliability Standard that clarifies the critical requirements for Emergency Operations while ensuring strong communication and coordination across the functional entities. NERC requests that the Commission approve proposed Reliability Standard EOP-011-1 and find that the proposed Reliability Standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest.

II. NOTICES AND COMMUNICATIONS

Notices and communications with respect to this filing may be addressed to the following:[7]

[7] Persons to be included on the Commission's service list are identified by an asterisk. NERC respectfully requests a waiver of Rule 203 of the Commission's regulations, 18 C.F.R. § 385.203 (2013), to allow the inclusion of more than two persons on the service list in this proceeding.

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III. BACKGROUND

A. Regulatory Framework

By enacting the Energy Policy Act of 2005,[8] Congress entrusted the Commission with the duties of approving and enforcing rules to ensure the reliability of the nation's Bulk-Power System, and with the duties of certifying an ERO that would be charged with developing and enforcing mandatory Reliability Standards, subject to Commission approval. Section 215(b)(1)[9] of the FPA states that all users, owners, and operators of the Bulk-Power System in the United States will be subject to Commission-approved Reliability Standards. Section 215(d)(5)[10] of the FPA authorizes the Commission to order the ERO to submit a new or modified Reliability Standard. Section 39.5(a)[11] of the Commission's regulations requires the ERO to file with the Commission for its approval each Reliability Standard that the ERO proposes should become mandatory and enforceable in the United States, and each modification to a Reliability Standard that the ERO proposes should be made effective.

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8 16 U.S.C. § 824o (2006).
9 *Id.* § 824(b)(1).
10 *Id.* § 824o(d)(5).
11 18 C.F.R. § 39.5(a) (2012).

The Commission has the regulatory responsibility to approve Reliability Standards that protect the reliability of the Bulk-Power System and to ensure that such Reliability Standards are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Pursuant to Section 215(d)(2) of the FPA[12] and Section 39.5(c)[13] of the Commission's regulations, the Commission will give due weight to the technical expertise of the ERO with respect to the content of a Reliability Standard.

B. NERC Reliability Standards Development Process

The proposed Reliability Standard was developed in an open and fair manner and in accordance with the Commission-approved Reliability Standard development process.[14] NERC develops Reliability Standards in accordance with Section 300 (Reliability Standards Development) of its Rules of Procedure and the NERC Standard Processes Manual.[15] In its ERO Certification Order, the Commission found that NERC's proposed rules provide for reasonable notice and opportunity for public comment, due process, openness, and a balance of interests in developing Reliability Standards and thus satisfies certain of the criteria for approving Reliability Standards.[16] The development process is open to any person or entity with a legitimate interest in the reliability of the Bulk-Power System. NERC considers the comments of all stakeholders, and a vote of stakeholders and the NERC Board of Trustees is required to approve a Reliability Standard before the Reliability Standard is submitted to the Commission for approval.

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[12] 16 U.S.C. § 824o(d)(2).

[13] 18 C.F.R. § 39.5(c)(1).

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

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

[16] 116 FERC ¶ 61,062 at P 250 (2006).

C. History of Project 2009-03, Emergency Operations

NERC is required to conduct a periodic review of each NERC Reliability Standard at least once every 10 years, or once every five years for any Reliability Standard approved by the American National Standards Institute as an American National Standard. The Emergency Operations Five-Year Review Team ("EOP FYRT") was appointed by the Standards Committee Executive Committee on April 22, 2013. The EOP FYRT reviewed the following Emergency Operations standards: EOP-001-2.1b (Emergency Operations Planning), EOP-002-3.1 (Capacity and Energy Emergencies) and EOP-003-2 (Load Shedding Plans) to determine if the standards should be retained, retired or if revisions were needed in the scope of this project in relation to P81 criteria, Independent Expert report and FERC directives.

The scope of the review included consideration of recommendations from the Industry Expert Review Panel report, Paragraph 81 recommendations and criteria, outstanding FERC Order No. 693 directives, and industry comments. The EOP FYRT posted its draft recommendations to revise the standards for stakeholder comment. After reviewing stakeholder comments, the EOP FYRT submitted its final recommendations to the Standards Committee, along with a Standard Authorization Request ("SAR"). This SAR replaced an earlier SAR, and the new SAR provided the scope for the work of Project 2009-03. The EOP drafting team implemented the EOP FYRT recommendations into proposed reliability standard EOP-011-1.

IV. <u>JUSTIFICATION FOR APPROVAL</u>

As discussed in detail in **Exhibit C**, proposed Reliability Standard EOP-011-1--Emergency Operations satisfies the Commission's criteria in Order No. 672 and is just, reasonable, not unduly discriminatory or preferential, and in the public interest. The purpose of proposed Reliability Standard EOP-011-1 is to address the effects of operating Emergencies by ensuring that each Transmission Operator and Balancing Authority has developed Operating

Plans to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator Area. Provided below is an explanation of the applicability of the proposed Reliability Standard and a justification on a Requirement-by-Requirement basis.

A. Justification on a Requirement-by-Requirement Basis for EOP-011-1 – Emergency Operations

The proposed Reliability Standard consists of six Requirements and Attachment 1 and is applicable to Balancing Authorities, Reliability Coordinators, and Transmission Operators. Attachment 1 describes the levels used by the Reliability Coordinator when communicating the condition of a Balancing Authority that is experiencing an Energy Emergency.

Proposed Requirement R1 addresses the need for Transmission Operators to develop, maintain and implement Operating Plans to mitigate operating Emergencies and specifies minimum requirements for the plans.[17] Proposed Requirement R2 addresses the need for Balancing Authorities to develop, maintain, and implement Operating Plans to mitigate Capacity Emergencies and Energy Emergencies. Proposed Requirement R3 requires Reliability Coordinators to review the Operating Plans submitted by Transmission Operators and Balancing Authorities and is designed to ensure that there is appropriate coordination with respect to reliability risks identified in those Operating Plans. Proposed Requirement R4 requires Transmission Operators and Balancing Authorities to resolve any issues identified by the Reliability Coordinator during its review of plans submitted pursuant to Requirement R3 and resubmit the plan to the Reliability Coordinator for additional review.

[17] An "Operating Plan" is defined in the *Glossary of Terms Used in NERC Reliability Standards* as "A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan."

Proposed Requirements R5 and R6 address communication and coordination by Reliability Coordinators during an Emergency. Proposed Requirement R5 requires Reliability Coordinators to notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators within 30 minutes of receiving an Emergency notification from a Balancing Authority or Transmission Operator. Requirement R6 requires a Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area to declare an Energy Emergency Alert, as detailed in Attachment 1. Collectively, these Requirements satisfy the Commission's directives in Order No. 693 and are intended to streamline the requirements for Emergency Operations.

Proposed Requirements

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable:

- **1.1. Roles and responsibilities for activating the Operating Plan(s);**
- **1.2. Processes to prepare for and mitigate Emergencies including:**
  - **1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;**
  - **1.2.2. Cancellation or recall of Transmission and generation outages;**
  - **1.2.3. Transmission system reconfiguration;**
  - **1.2.4. Redispatch of generation request;**
  - **1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and**
  - **1.2.6. Reliability impacts of extreme weather conditions.**

Requirement R1 of proposed Reliability Standard EOP-011-1 requires Transmission Operators to develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plans to mitigate operating Emergencies. An Operating Plan can be one plan or it can be multiple plans. An Operating Plan is implemented by carrying out its stated actions. The

Operating Plan must include the elements enumerated in Parts 1.1 and 1.2 (including sub-parts 1.2.1 through 1.2.6). Given the need for flexibility to account for regional differences and pre-existing methods for mitigating Emergencies, the drafting team included the language "as applicable." Where any of these specified elements are not applicable, an entity should provide in the plan that the element is not applicable and include an explanation. Transmission Operators are expected to "maintain" Operating Plans by keeping them current and up-to-date. In accordance with the principles of Paragraph 81, the proposed Reliability Standard does not include a specific timeframe or requirement to update Operating Plans as entities are expected to maintain their plans on an on-going and as-needed basis.[18]

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable:

- **2.1. Roles and responsibilities for activating the Operating Plan(s);**
- **2.2. Processes to prepare for and mitigate Emergencies including:**
  - **2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;**
  - **2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;**
  - **2.2.3. Managing generating resources in its Balancing Authority Area to address:**
    - **2.2.3.1. capability and availability;**
    - **2.2.3.2. fuel supply and inventory concerns;**
    - **2.2.3.3. fuel switching capabilities; and**
    - **2.2.3.4. environmental constraints.**
  - **2.2.4. Public appeals for voluntary Load reductions;**
  - **2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;**
  - **2.2.6. Reduction of internal utility energy use;**
  - **2.2.7. Use of Interruptible Load, curtailable Load and demand response;**
  - **2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable**

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18 *See* Criterion B1, B3 and B5. Paragraph 81 White Paper *available at*: http://www.nerc.com/pa/Stand/Project%20201302%20Paragraph%2081%20RF/P81_Phase_I_technical_white_paper_FINAL.pdf.

of being implemented in a timeframe adequate for mitigating the Emergency; and

2.2.9. Reliability impacts of extreme weather conditions.

Proposed Requirement R2 requires Balancing Authorities to develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. Proposed Requirement R2 specifies that the Balancing Authorities should complete these actions "within its Balancing Authority Area" to articulate the regional bounds of the responsibility of the Balancing Authority. As with proposed Requirement R1, an Operating Plan can be one plan or it can be multiple plans and is implemented by carrying out its stated actions. Balancing Authorities are expected to "maintain" Operating Plans by keeping them current and up-to-date. In accordance with the principles of Paragraph 81, the proposed Reliability Standard does not include a specific timeframe or requirement to update Operating Plans as entities are expected to maintain their plans on an on-going and as-needed basis.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans.

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

Proposed Requirement R3 ensures that Reliability Coordinators review Operating Plans submitted by Transmission Operators and Balancing Authorities in a timely manner and to identify specific reliability risks. For those Plans that require revisions, the Reliability Coordinator is required by Proposed Requirement R3 Part 3.1.3 to articulate a timeframe for resubmittal of the revised plan. This is consistent with the Reliability Coordinator's role within the NERC Functional Model.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator.

Proposed Requirement R4 supports the coordination of Operating Plans within a Reliability Coordinator Area in order to identify and correct any Wide Area reliability risks. Proposed Requirement R4 is designed to ensure that the Reliability Coordinator's review of Operating Plans is effective. Any reliability risks identified by the Reliability Coordinator must be addressed by the Transmission Operator or Balancing Authority within a time period specified by the Reliability Coordinator. A specific timeframe is not included in order to allow entities flexibility to address the identified risks, which could vary widely from entity to entity. The time period requested by the Reliability Coordinator to the Transmission Operator and Balancing Authority to update the Operating Plan(s) will depend on the scope and urgency of the requested change.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

Proposed Requirement R5 is designed to ensure that there is communication among Balancing Authorities and Transmission Operators when an entity is experiencing an Emergency. As the entity with the Wide Area view, the Reliability Coordinator is designated as the entity responsible for ensuring that this communication occurs and in a timely manner.

The drafting team used the existing requirement in currently-effective Reliability Standard EOP-002-3.1 for the Balancing Authority and added the words "within 30 minutes from the time of receiving notification" to the requirement to communicate the intent that timeliness is important, while balancing the concern that in an Emergency there may be a need to alleviate excessive notifications on Balancing Authorities and Transmission Operators. By adding this time limitation, a measurable standard is set for when the Reliability Coordinator must complete these notifications.

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1.

Proposed Requirement R6 requires Reliability Coordinators to declare an Energy Emergency Alert when a Balancing Authority is experiencing a potential or actual Energy Emergency. The declaration of the Energy Emergency by the Reliability Coordinator instead of the Balancing Authority is consistent with current industry practice and ensures that Energy Emergencies are not declared precipitously.

B. Commission Directives Addressed

As explained in **Exhibit F** and detailed below, the proposed Reliability Standard satisfies seven Commission directives from Order No. 693, including in an equally efficient and effective alternative manner.

1. Order No. 693, Paragraph 561, Optimum Number of Continent-Wide System States

In Order No. 693, the Commission directed NERC to determine the optimum number of

Continent-wide system states and their attributes and to modify EOP-001-0 through the Reliability Standards development process to accomplish this objective.[19] While proposed Reliability Standard EOP-011-1 does not define the optimum number of continent-wide system states, as Emergency system states are case-specific and therefore difficult to define, the proposed standard does require Transmission Operators and Balancing Authorities to identify conditions that put them into an Emergency state via proposed Requirements R1 and R2. Therefore, this directive from Order No. 693 has been satisfied in an equally efficient and effective manner.

2. Order No. 693, Paragraph 562, Consideration of a Pilot Program

In Order No. 693, the Commission directed NERC to consider a pilot program as it modifies EOP-010-1. "Such testing will help assure that all applicable entities and their personnel understand how the terms will be used and will allow operators to train staff to make any necessary changes to their policies and procedures."[20] Given that the drafting team met the directive in Paragraph 561 of Order No. 693 in an alternative manner, the directive in Paragraph 562 is not directly applicable. The drafting team considered this proposal, thereby satisfying the directive--however, the team concluded that a field test would not be a viable option with Emergency states, as one would not intentionally create an Emergency state on the system. Further, proposed Reliability Standard EOP-010-1 provides flexibility by allowing Transmission Operators and Balancing Authorities to identify conditions that put them into an Emergency state via proposed Requirements R1 and R2. For these reasons, the directive from Order No. 693 has been satisfied in an equally efficient and effective manner.

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[19] Order No. 693 at P 561.
[20] Order No. 693 at P 562.

3. Order No. 693, Paragraph 571, Clarification of Insufficient Transmission Capability

In Order No. 693, the Commission directed NERC to consider whether to clarify the term "insufficient transmission capability" and referenced the NOPR issued prior to Order No. 693 where the Commission noted that Reliability Standard EOP-002-1 addresses only generation capacity and energy emergencies and does not address emergencies resulting from inadequate transmission capability.[21] Proposed Reliability Standard EOP-011-1 includes transmission-related items that impact transmission capability in the Transmission Operator's Emergency Operating Plan in Parts 1.2.2 through 1.2.4 of Requirement R1.

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

Redispatch of generation is included because it can impact transmission capability. Typically, redispatching generation means that you are lowering generation in one area and raising it in another. This changes the transmission flows and can have a significant impact and reduce any real or potential System Operating Limit and Interconnection Reliability Operating Limit exceedances that an entity might have, plus it could also free up transmission capability to import power from other Balancing Authorities.

While NERC did not clarify the term "insufficient transmission capability," proposed Reliability Standard EOP-011-1 addresses emergencies resulting from inadequate transmission capability and is therefore an equally effective and efficient alternative.

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[21] Order No. 693 at P 571.

4. Order No. 693, Paragraph 573, Technically Feasible Options

In Order No. 693, the Commission directed NERC to modify Reliability Standard EOP-002-2 to include all technically feasible options in the management of emergencies.[22] "These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements."[23]

Requirements R1 and R2 of proposed Reliability Standard EOP-011-1 include a variety of options to prepare for and mitigate emergencies. Specifically, management of generation resources is included in Part 2.2.3 and demand response is included in Part 2.2.7 of Requirement R2 of proposed Reliability Standard EOP-011-1. For these reasons, the proposed Reliability Standard EOP-011-1 satisfies the Commission's directive in Paragraph 573 of Order No. 693.

5. Order No. 693, Paragraph 595, Load Shedding Capability

In Order No. 693, the Commission directed NERC to modify Reliability Standard EOP-003-1 to:

> ensure that adequate load shedding capabilities are provided so that system operators have an effective operating measure of last resort to contain system emergencies and prevent cascading. The Commission recognizes that the amount of load shedding capability required is dependent on system characteristics and therefore it may not be feasible to have a uniform nationwide load shedding capability. This, however, does not preclude a uniform nationwide criterion on the methodology for establishing load shedding capability that would specify the minimum amount of load shedding capability that should be provided based on system characteristics and conditions and the maximum amount of delay before load shedding can be implemented.

Requirement R1 of proposed Reliability Standard EOP-011-1, Part 1.2.5 addresses load shedding and provides that Transmission Providers include in their Operating Plan(s): "Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load

[22] Order No. 693 at P 573.
[23] *Id.*

shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency." Requirement R2 of proposed Reliability Standard EOP-011-1, Part 2.2.8 also addresses load shedding and provides that Balancing Authorities include in their Operating Plan(s): "Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency." Collectively, these Requirements address the difficulties of establishing a uniform nationwide load shedding capability and allow entities the flexibility needed to account for differences in system characteristics. For these reasons, proposed Reliability Standard EOP-011-1 satisfies the Commission's directive in Paragraph 595 of Order No. 693.

6. Order No. 693, Paragraphs 597 and 603, Periodic Drills of Simulated Load Shedding

In Order No. 693, the Commission stated that "periodic drills of simulated load shedding should involve all participants required to ensure successful implementation of load shedding plans. As such, the drills should extend beyond system operators to distribution operators and LSEs. The Reliability Standard should require periodic drills by entities subject to section 215, and require those entities to seek participation by other entities. The drills should test the readiness and functionality of the load shedding plans, including, at times, the actual deployment of personnel."[24] In Order No. 693, the Commission directed NERC to modify Reliability Standard EOP-003-1 to require periodic drills of simulated load shedding.[25] As noted herein, Reliability Standard EOP-003-1 is proposed for retirement. However, this directive is addressed

[24] Order No. 693 at P 597.
[25] Order No. 693 at P 603.

by several currently-effective Reliability Standards, including EOP-006-2 – System Restoration Coordination, and PER-005-1 – Operations Personnel Training.

Currently-effective Reliability Standard EOP-006-2, Requirement R10 addresses periodic drills and provides:

> R10. Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted.
>
> R10.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least every two calendar years.

While Requirement R10 and Sub-Requirement 10.1 do not explicitly require simulated load shedding, it certainly could be included in the required drills and exercises. In addition, Requirement R3 of currently-effective Reliability Standard PER-005-1 provides:

> R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel.
>
> R3.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions.

Again, while not explicitly included, the training required by PER-005-1 (and included in Requirement R4 of future-effective Reliability Standard PER-005-2) could include simulated load shedding. For these reasons the Commission's directive has been addressed in an equally effective and efficient manner.

7. Order No. 693, Paragraph 601, Consideration of Comments

In Order No. 693, NERC directed FERC to consider comments submitted regarding coordination of trip settings and automatic and manual load shedding plans. The drafting team considered these comments and addressed the coordination and planning of automatic and manual Load shedding by requiring Transmission Operators and Balancing Authorities to have a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies. Therefore, the Commission's directive in Paragraph 601 of Order No. 693 has been addressed.

C. Proposed Definition of "Energy Emergency"

The currently-effective definition of "Energy Emergency" is proposed to be revised as follows:

> Energy Emergency - A condition when a Load-Serving Entity <u>or Balancing Authority</u> has exhausted all other resource options and can no longer meet its ~~customers'~~ expected ~~energy~~ <u>Load</u> obligations.

The proposed revisions are intended to clarify that an Energy Emergency is not necessarily limited to a Load-Serving Entity. The drafting team evaluated the impact of these revisions on the body of NERC Reliability Standards and determined that the proposed revisions do not change the reliability intent of other requirements of Definitions.

D. Justification for Retirements

Proposed Reliability Standard EOP-011-1 replaces currently-effective Reliability Standards EOP-001-2.1b, EOP-002-3.1, and EOP-003-2. Provided below is an explanation of how these currently-effective Reliability Standards are addressed and improved upon in proposed Reliability Standard EOP-011-1. Additional information is also included in **Exhibit D**.

1. Justification for Retirement of Reliability Standard EOP-001-2.1b

Currently-effective Reliability Standard EOP-001-2.1b consists of six requirements and is applicable to Balancing Authorities and Transmission Operators. The purpose of currently-effective Reliability Standard EOP-001-2.1b is to require Transmission Operators and Balancing Authorities to develop, maintain, and implement a set of plans to mitigate operating emergencies.

Requirements R1 and R2 of proposed Reliability Standard EOP-011-1 address Requirements R1 through R5 of currently-effective Reliability Standard EOP-001-2.1b.

Requirement R1 of currently-effective Reliability Standard EOP-001-2.1b requires Balancing Authorities to have operating agreements with adjacent Balancing Authorities is replaced by proposed Requirement R2 of Reliability Standard EOP-011-1 which requires Balancing Authorities to develop, maintain and implement a Reliability-Coordinator reviewed Operating Plan. Currently-effective Reliability Standard EOP-001-2.1b, Requirement R2 which requires Transmission Operators and Balancing Authorities to develop, maintain and implement a set of plans to mitigate operating emergencies on the transmission system and for insufficient generating capacity and is replaced by proposed Requirements R1 and R2 of Reliability Standard EOP-011-1. Requirements R1 and R2 of proposed Reliability Standard EOP-011-1 require Transmissions Operators and Balancing Authorities to develop, maintain and implement a Reliability-Coordinator reviewed Operating Plan.

Currently-effective Reliability Standard EOP-001-2.1b, Requirement R2.3 requires Transmission Operators and Balancing Authorities to develop, maintain and implement a set of plans for load shedding, and this requirement is maintained in proposed Reliability Standard EOP-011-1 Requirement R1, Part 1.2.5.

Currently-effective Reliability Standard EOP-001-2.1b, Requirement R3 requires Transmission Operators and Balancing Authorities to have emergency plans and specifies elements that must be included in those plans. Proposed Requirements R1 and R2 of Reliability Standard EOP-011-1 require Transmission Operators and Balancing Authorities to develop, maintain, and implement a Reliability-Coordinator reviewed Operating Plan to mitigate operating Emergencies, and sub-parts of Requirements R1 and R2 specify elements that must be included in those plans.

Currently-effective Reliability Standard EOP-001-2.1b, Requirement R6 requires Transmission Operators and Balancing Authorities to coordinate emergency plans with other Transmission Operators and Balancing Authorities as appropriate, and is proposed for retirement. For these reasons, the proposed retirement of currently-effective Reliability Standard EOP-001-2.1b is expected to have little to no impact on the reliability of the Bulk-Power System.

2. Justification for Retirement of Reliability Standard EOP-002-3.1

Currently-effective Reliability Standard EOP-002-3.1 consists of nine requirements and is applicable to Balancing Authorities, Reliability Coordinators, and Load-Serving Entities. The purpose of currently-effective Reliability Standard EOP-002-2.1 is to ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.

Requirement R1 of currently-effective Reliability Standard EOP-002-3.1 states that each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies. As the Commission noted in Order No. 693-A, "a reliability coordinator's authority to issue directives arises out of the Commission's approval of Reliability Standards that mandate compliance with such directives."[26] Proposed Reliability Standard IRO-001-4, Requirement R1 states that each Reliability Coordinator shall act to address the reliability of its Reliability Coordinator Area via direct actions or by issuing Operating Instructions. Proposed Reliability Standard IRO-001-4 is part of Project 2014-03 and is being submitted for Commission approval in a separate petition.

[26] Order No. 693-A at P 112.

Requirement R2 of proposed Reliability Standard EOP-011-1 replaces Requirements R2 through R7 of currently-effective Reliability Standard EOP-002-3.1. Requirement R2 of currently-effective Reliability Standard EOP-002-3.1 requires Balancing Authorities to take one or more actions as described in its capacity and energy emergency plan and this is addressed in the implementation of Reliability Coordinator-reviewed Operating Plans required by Requirement R2 of proposed Reliability Standard EOP-011-1. Requirement R3 of currently-effective Reliability Standard EOP-002-3.1 requires Balancing Authorities experiencing an operating capacity or energy emergency to communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities. This notification is addressed in Part 2.2.1 of Requirement R2 of proposed Reliability Standard EOP-011-1.
The drafting team determined that to have a Transmission Operator or Balancing Authority contact other Transmission Operators and Balancing Authorities takes them away from the Emergency at hand, plus they do not have a wide-area view. The Reliability Coordinator can give an indication of impact and make high-level determinations. The Reliability Coordinator has the wide-area overview and can quickly determine impacts of neighboring Transmission Operators, Balancing Authorities and Reliability Coordinators. The Reliability Coordinator is to make contact within 30 minutes of notification pursuant to Requirement R5 of proposed Reliability Standard EOP-011-1. From there, Reliability Standards IRO-005, IRO-006 and IRO-007 would address the specific actions to be taken.

Requirement R4 of currently-effective Reliability Standard EOP-002-3.1 requires a Balancing Authority anticipating an operating capacity or energy emergency to perform all actions necessary and this is addressed in Part 2.2 of Requirement R2 of proposed Reliability Standard EOP-011-1, which requires Balancing Authorities to have processes to prepare for and mitigate Emergencies, including the elements listed in Parts 2.2.1 through 2.2.3. Requirement

R5 of currently-effective Reliability Standard EOP-002-3.1 requires a deficient Balancing Authority to only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. This requirement is addressed by Commission-approved Reliability Standard BAL-003-1, which is designed to ensure that Balancing Authorities do not lean on an Interconnection's frequency. Requirement R6 of currently-effective Reliability Standard EOP-002-3.1 specifies remedies that a Balancing Authority shall implement when it cannot comply with the Control Performance and Disturbance Control Standards. These remedies are incorporated into Parts 2.2.1 through 2.2.9 of proposed Reliability Standard EOP-011-1. Requirement R7 of currently-effective Reliability Standard EOP-002-3.1 applies when a Balancing Authority has exhausted the remedies in Requirement R6 and requires Balancing Authorities to manually shed load and request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1. This requirement is incorporated into Requirement R2 of proposed Reliability Standard EOP-011-1, which requires Balancing Authorities to include processes to prepare for and mitigate Emergencies in their Operating Plans.

Requirement R8 of currently-effective Reliability Standard EOP-002-3.1 is addressed by Requirement R6 of proposed Reliability Standard EOP-011-1. Requirement R8 requires a Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency to initiate an Energy Emergency Alert as detailed in Attachment 1. The Reliability Coordinator must act to mitigate the emergency, including requesting emergency assistance. Requirement R6 of proposed Reliability Standard EOP-011-1 requires Reliability Coordinators that have a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area to declare an Energy Emergency Alert as detailed in Attachment 1.

For these reasons, the proposed retirement of currently-effective Reliability Standard EOP-002-3.1 is expected to have little to no impact on the reliability of the Bulk-Power System.

3. Justification for Retirement of Reliability Standard EOP-003-2

Currently-effective Reliability Standard EOP-003-2 consists of eight requirements and is applicable to Transmission Operators and Balancing Authorities. Requirement R2, R4 and R7 of currently-effective Reliability Standard EOP-003-2 are addressed by proposed Reliability Standard PRC-010-1, which is part of Project 2008-02, Undervoltage Load Shedding and Underfrequency Load Shedding. Proposed Reliability Standard PRC-010-1 was coordinated with the instant project and is proposed for Commission approval in a separate petition.

Requirement R1 of currently-effective Reliability Standard EOP-003-2 requires Transmission Operators or Balancing Authorities operating with insufficient generation or transmission capacity to shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection. This requirement is addressed by proposed Requirements R1 and R2 of proposed Reliability Standard EOP-011-1, which require Transmission Operators and Balancing Authorities to develop and implement Operating Plans that include processes to prepare for and mitigate Emergencies, including provisions for Load Shedding.

Requirement R2 of currently-effective Reliability Standard EOP-003-2 requires Transmission Operators to establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner or Planning Coordinator determine that an undervoltage load shedding scheme is required. This requirement is addressed by Requirement R1 of proposed Reliability Standard PRC-010-1 – Undervoltage Load Shedding, which provides:

R1. Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS Program. The evaluation shall include, but is not limited to, studies and analyses that show:

1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs.

Requirement R1 of proposed Reliability Standard PRC-010-1 also replaces Requirement R4 of currently-effective Reliability Standard EOP-003-2, which requires Transmission Operators to consider one or more of the following factors in designing an automatic undervoltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels. The elements listed in Requirement R4 of currently-effective Reliability Standard EOP-003-2 are integrated into Part 1.1 of Requirement R1 of proposed Reliability Standard PRC-010-1, as explained in the Guidelines and Technical Basis section of the standard. Requirement R7 of currently-effective Reliability Standard EOP-003-2, requires Transmission Operators to coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage or power flow conditions. Part 1.2 of proposed Reliability Standard PRC-010-1 addresses the elements of Requirement R7 of currently-effective Reliability Standard EOP-003-2, as explained in the Guidelines and Technical Basis section of the standard.

Requirement R3 of currently-effective Reliability Standard EOP-003-2 requires Transmission Operators and Balancing Authorities to coordinate load shedding plans, excluding automatic underfrequency load shedding plans, among other interconnected Transmission

Operators and Balancing Authorities. This coordination is addressed by Requirements R1 and R2 of proposed Reliability Standard EOP-011-1, as explained herein.

Requirement R5 of currently-effective Reliability Standard EOP-003-2 requires Transmission Operators or Balancing Authorities to implement load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown. This requirement is addressed by Requirements R1 and R2 of proposed Reliability Standard EOP-011-1, which require Transmission Operators and Balancing Authorities to develop and implement Operating Plans that include processes to prepare for and mitigate Emergencies, including provisions for Load Shedding.

Requirement R6 of currently-effective Reliability Standard EOP-003-2 requires that after a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load. Similar to Requirement R1 and R5 of currently-effective Reliability Standard EOP-003-2, this requirement is addressed by Requirements R1 and R2 of proposed Reliability Standard EOP-011-1, which require Transmission Operators and Balancing Authorities to develop and implement Operating Plans that include processes to prepare for and mitigate Emergencies, including provisions for Load Shedding.

Requirement R8 of currently-effective Reliability Standard EOP-003-2 requires Transmission Operators or Balancing Authorities to have plans for operator controlled manual load shedding to respond to real-time emergencies, and the Transmission Operator or Balancing Authority must be capable of implementing the load shedding in a timeframe adequate for responding to the emergency. This requirement is addressed by Requirements R1 and R2 of proposed Reliability Standard EOP-011-1, which require Transmission Operators and Balancing

Authorities to develop and implement Operating Plans that include processes to prepare for and mitigate Emergencies, including provisions for Load Shedding. Part 1.2.5 of Requirement R1 and Part 2.2.8 of Requirement R2 of proposed Reliability Standard EOP-011-1 also incorporate the concept of a timeframe adequate for mitigating an Emergency.

For these reasons, the proposed retirement of currently-effective Reliability Standard EOP-003-2 is expected to have little to no impact on the reliability of the Bulk-Power System.

E. Enforceability of EOP-011-1

The proposed Reliability Standard includes Violation Severity Levels ("VSLs") and Violation Risk Factors ("VRFs"). The VSLs provide guidance on the way that NERC will enforce the Requirements of the proposed Reliability Standard. The VRFs are one of several elements used to determine an appropriate sanction when the associated Requirement is violated. The VRFs assess the impact to reliability of violating a specific Requirement. The VRFs and VSLs for the proposed Reliability Standards comport with NERC and Commission guidelines related to their assignment. For a detailed review of the VRFs, the VSLs, and the analysis of how the VRFs and VSLs were determined using these guidelines, please see **Exhibit E**.

The proposed Reliability Standard also include Measures that support each Requirement by clearly identifying what is required and how the Requirement will be enforced. These Measures help ensure that the Requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.[27]

[27] Order No. 672 at P 327 ("There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner.").

V. **CONCLUSION**

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

- approve the proposed Reliability Standard and Definition and associated elements included in **Exhibit A**, effective as proposed herein;
- approve the implementation plan included in **Exhibit B** as proposed herein.

Respectfully submitted,

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Date: December 29, 2014

Exhibit A

Proposed Reliability Standard, EOP-011-1—Emergency Operations

A. Introduction

1. **Title:** **Emergency Operations**
2. **Number:** **EOP-011-1**
3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plan(s) to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator Area.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator
5. **Effective Date:**

   See *Implementation Plan for EOP-011-1*
6. **Background:**

   EOP-011-1 consolidates requirements from three standards: EOP-001-2.1b, EOP-002-3.1, and EOP-003-2.

   The standard streamlines the requirements for Emergency operations for the Bulk Electric System into a clear and concise standard that is organized by Functional Entity. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

1.2.6. Reliability impacts of extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

2.2.9. Reliability impacts of extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated e-mails or other correspondences that it reviewed Transmission Operator and Balancing Authority Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators .

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The Balancing Authority, Reliability Coordinator, and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4and Measures M1 and M4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

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

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

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	Real-time Operations, Operations Planning, Long-term Planning	High		The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission s Operator Area but failed to implement it.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	Real-time Operations, Operations Planning, Long-term Planning	High	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to implement it.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Planning	High	N/A	N/A	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator.
R4	Operations Planning	High	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit tis Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	Real-time Operations	High	N/A	N/A	The Reliability Coordinator that received an Emergency	The Reliability Coordinator that received an Emergency

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators but failed to notify within 30 minutes from the time of receiving notification.	notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	Real-time Operations	High	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
1	November 13, 2014	Adopted by Board of Trustees	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

Attachment 1-EOP-011-1
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use.**

Circumstances:

- The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect**.

Circumstances:

- The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
- An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.

- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities **and market participants**. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

3. EEA 3 —Firm Load interruption is imminent or in progress.

Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre-Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA**.**

0.1 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

Guidelines and Technical Basis

Rationale:

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

Rationale for R1:

The EOP SDT examined the recommendation of the EOP Five-Year Review Team (FYRT) and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Transmission Operator to create an Operating Plan(s) for mitigating operating Emergencies in its Transmission Operator Area.

The Operating Plan(s) can be one plan, or it can be multiple plans.

"Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency" was retained. This is a process in the plan(s) that determines when the Transmission Operator must notify its Reliability Coordinator.

To meet the associated measure, an entity would likely provide evidence that such an evaluation was conducted along with an explanation of why any overlap of Loads between manual and automatic load shedding was unavoidable or reasonable.

An Operating Plan(s) is implemented by carrying out its stated actions.

If any Parts of Requirement R1 are not applicable, the Transmission Operator should note "not applicable" in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s).

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shed schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R1 Part 1.2.5. is to minimize, as much as possible, the use of manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If any entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review their automatic Load shedding schemes and coordinate their manual processes so that any overlapping use of Loads is avoided to the extent reasonably possible.

Rationale for R2:
To address the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1, the EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. EOP-011-1 also establishes a separate requirement for the Balancing Authority to create its Operating Plan(s) to address Capacity and Energy Emergencies.
The Operating Plan(s) can be one plan, or it can be multiple plans.

An Operating Plan(s) is implemented by carrying out its stated actions.

If any Parts of Requirement R2 are not applicable, the Balancing Authority should note "not applicable" in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s).

The EOP SDT retained the statement "Operator-controlled manual Load shedding," as it was in the current EOP-003-2 and is consistent with the intent of the EOP SDT.

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shedding schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R2 Part 2.2.8. is to minimize as much as possible the use manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If an entity manually sheds a Load that was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review its automatic Load shedding schemes and coordinate its manual processes so that any overlapping use of Loads is avoided to the extent possible.

The EOP SDT retained Requirement R8 from EOP-002-3.1 and added it to the Parts in Requirement R2.

Rationale for R3:
The SDT agreed with industry comments that the Reliability Coordinator does not need to approve BA and TOP plan(s). The SDT has changed this requirement to remove the approval but still require the RC to review each entity's plan(s), looking specifically for reliability risks. This is consistent with the Reliability Coordinator's role within the Functional Model and meets the FERC directive regarding the RC's involvement in Operating Plan(s) for mitigating Emergencies.

Rationale for Requirement R4:
Requirement R4 supports the coordination of Operating Plans within a Reliability Coordinator Area in order to identify and correct any Wide Area reliability risks. The EOP SDT expects the Reliability Coordinator to make a reasonable request for response time. The time period requested by the Reliability Coordinator to the Transmission Operator and Balancing Authority to update the Operating Plan(s) will depend on the scope and urgency of the requested change.

Rationale for R5

The EOP SDT used the existing requirement in EOP-002-3.1 for the Balancing Authority and added the words "within 30 minutes from the time of receiving notification" to the requirement to communicate the intent that timeliness is important, while balancing the concern that in an Emergency there may be a need to alleviate excessive notifications on Balancing Authorities and Transmission Operators. By adding this time limitation, a measurable standard is set for when the Reliability Coordinator must complete these notifications.

Rationale for Introduction

LSEs were removed from Attachment 1, as an LSE has no Real-time reliability functionality with respect to EEAs.

EOP-002-3.1 Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, as permitted in its transmission tariff, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ E-tag Specification v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.

Rationale for (2) Notification

The EOP SDT deleted the language, "*The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between RCs shall be held as necessary to communicate system conditions. The RC shall also notify the other RCs when the alert has ended*" as duplicative to proposed IRO-014-3 Requirement R1:

> R1**.** Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:
>
> **1.1** Communications and notifications, and the process to follow in making those notifications.
>
> **1.2** Energy and capacity shortages.
>
> **1.3** Control of voltage, including the coordination of reactive resources.
> Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.
>
> **1.5** Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas.
>
> **1.6** Provisions for weekly conference calls.

Rationale for EEA 2:
The EOP SDT modified the "Circumstances" for EEA 2 to show that an entity will be in this level when it has implemented its Operating Plan(s) to mitigate Emergencies but is still able to maintain Contingency Reserves.

Rationale for EEA 3:
This rationale was added at the request of stakeholders asking for justification for moving a lack of Contingency Reserves into the EEA3 category.

The previous language in EOP-002-3.1, EEA 2 used "Operating Reserve," which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently. Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using minimum Contingency Reserve in the language would eliminate some of the confusion. This is a different approach but the drafting team believes this is a good approach and was supported by several commenters.

Using Contingency Reserves (which is a subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that the point where a BA can no longer maintain this important Contingency Reserves margin is a most serious condition and puts the BA into a position where they are very close to shedding Load ("imminent or in progress"). The drafting team felt that this warrants categorization at the highest level of EEA.

Exhibit B

Implementation Plan for EOP-011-1

NERC
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Implementation Plan
Project 2009-03 – Emergency Operations

Standards Involved
Approval:
EOP-011-1 — Emergency Operations

Retirements:
- EOP-001-2.1b — Emergency Operations Planning
- EOP-002-3.1 — Capacity and Energy Emergencies
- EOP-003-2— Load Shedding Plans

Prerequisite Approvals
- PRC-010-1 in Project 2008-02 – Undervoltage Load Shedding

Revisions to the NERC Glossary of Terms
The following term is proposed for revision:

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its ~~customers'~~ expected ~~energy~~ Load obligations.

Applicable Entities
Reliability Coordinator
Balancing Authority
Transmission Operator

Conforming Changes to Other Standards
Project 2008-02 – Undervoltage Load Shedding (Requirement 1 of PRC-010): Project 2009-03 - Emergency Operations (EOP-011-1) retires EOP-003-2. Requirements R2, R4 and R7 of EOP-003-2, not being absorbed by EOP-011-1, are mapped to PRC-010-1, Requirement 1.

Effective Date
EOP-011-1 and the definition of "Energy Emergency" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard and definition shall

become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

EOP-011-1 is a consolidation of EOP-001-2.1b – Emergency Operations Planning, EOP-002-3.1 – Capacity and Energy Emergencies and EOP-003-2 – Load Shedding Plans. EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 shall retire at midnight of the day immediately prior to the effective date of EOP-011-1 in the particular jurisdiction in which the new standard is becoming effective.

Exhibit C

Order No. 672 Criteria for EOP-011-1

EXHIBIT C

Order No. 672 Criteria

In Order No. 672, the Commission identified a number of criteria it will use to analyze Reliability Standards proposed for approval to ensure they are just, reasonable, not unduly discriminatory or preferential, and in the public interest. [1] The discussion below identifies these factors and explains how proposed Reliability Standard EOP-011-1 and the proposed Definition of "Energy Emergency" have met or exceeded the criteria.

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

The proposed Reliability Standard achieves the specific reliability goal of addressing the effects of operating Emergencies by ensuring that each Transmission Operator and Balancing Authority has developed Operating Plans to mitigate such Emergencies and that those plans are coordinated within a Reliability Coordinator Area. Proposed Reliability Standard EOP-011-1 consolidates requirements from currently-effective Reliability Standards EOP-001-2.1b, EOP-002-3.1, and EOP-003-2 to streamline and clarify the critical requirements for Emergency operations for the Bulk Electric System. Specifically, proposed EOP-011-1 requires Transmission Operators and Balancing Authorities to develop Operating Plans and use those plans to mitigate operating Emergencies. The proposed standard achieves mitigation of the effects of operating Emergencies by requiring all entities to engage in necessary communication and coordination concerning Wide Area reliability risks caused by operating Emergencies

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

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

acknowledged in the Operating Plans.

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

Proposed Reliability Standard EOP-011-1 applies to Balancing Authorities, Reliability Coordinators, and Transmission Operators. In accordance with Order No. 672, the proposed standard is clear and unambiguous as to what is required and who is required to comply, as each of the six requirements of the proposed Reliability Standard clearly articulates the actions that such entities must take to comply.

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

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

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

[4] Order No. 672 at P 327.

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

Proposed Reliability Standard EOP-011-1 contains six measures that support each requirement by clearly identifying what is required and how the requirement will be enforced. These measures help provide clarity regarding how the requirements will be enforced, and they help ensure that the requirements will be enforced in a clear, consistent, and non-preferential manner and without prejudice to any party.

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

Proposed Reliability Standard EOP-011-1 achieves the reliability goal of addressing the effects of operating Emergencies effectively and efficiently in accordance with Order No. 672. The proposed Reliability Standard streamlines requirements applicable to Transmission Operators and Balancing Authorities for Emergency Operations for the Bulk Electric System and provides additional clarification on the critical requirements. The proposed Reliability Standard also ensures strong communication and coordination across Functional Entities and proper oversight by Reliability Coordinators with respect to Emergency Operations in order to effectively and efficiently achieve Wide Area reliability.

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

[5] Order No. 672 at P 328.

[6] Order No. 672 at P 328.

reliability.[7]

Proposed Reliability Standard EOP-011-1 does not reflect a "lowest common denominator" approach. To the contrary, the proposed Reliability Standard represents an improvement over existing practices for addressing the effects of operating Emergencies and is more stringent than the current Emergencies Operations response requirements in currently-effective NERC Reliability Standards EOP-001-2.1b, EOP-002-3.1, and EOP-003-2.

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

Proposed Reliability Standard EOP-011-1 is designed to apply throughout North America to the maximum extent and does not favor one geographic area or regional model. Because the proposed standard applies throughout North America, it has been designed to properly account for variations across all organizations and corporate structures.

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

Proposed Reliability Standard EOP-011-1 will not cause undue negative effect on

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

[8] Order No. 672 at P 331.

[9] Order No. 672 at P 332. As directed by section 215 of the FPA, FERC itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential

competition or result in any unnecessary restrictions. Specifically, the proposed Reliability Standard does not restrict the ability of the Transmission Operator, Balancing Authority, or Reliability Coordinator to employ additional means to mitigate the effects of operating Emergencies.

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

The proposed effective date for proposed Reliability Standard EOP-011-1 and the proposed Definition of "Energy Emergency" is just and reasonable. NERC proposes an effective date of the first day of the first calendar quarter that is twelve months after applicable regulatory approval. The proposed implementation period is designed to allow sufficient time for the applicable entities to make any changes in their internal process necessary to implement proposed EOP-011-1. The proposed Implementation Plan is attached as **Exhibit B**.

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

The proposed Reliability Standard and Definition were developed in accordance with NERC's Commission-approved, ANSI-accredited processes for developing and approving Reliability Standards.[12] **Exhibit G** includes a summary of the Reliability Standard development proceedings, and details the processes followed to develop the Reliability Standard and

manner. It should not create an undue advantage for one competitor over another.

[10] Order No. 672 at P 333.

[11] Order No. 672 at P 334.

[12] *See* NERC Rules of Procedure, Section 300 (Reliability Standards Development) and Appendix 3A (Standard Processes Manual).

Definition. These processes included, among other things, comment and balloting periods. Additionally, all meetings of the drafting team were properly noticed and open to the public.

11. NERC must explain any balancing of vital public interests in the development of proposed Reliability Standards.[13]

NERC has identified no competing public interests regarding the request for approval of proposed Reliability Standard EOP-011-1 and Definition of "Energy Emergency." No comments were received that indicated the proposed Reliability Standard or Definition conflict with other vital public interests.

12. Proposed Reliability Standards must consider any other appropriate factors.[14]

No other negative factors relevant to whether proposed Reliability Standard EOP-011-1 is just and reasonable were identified.

[13] Order No. 672 at P 335.

[14] Order No. 672 at P 323.

Exhibit D

Mapping Document

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Project 2009-03 - Emergency Operations

Mapping Document

Project Purpose

The Emergency Operations Five-Year Review Team (EOP FYRT) was appointed by the Standards Committee Executive Committee on April 22, 2013. The EOP FYRT has reviewed the following Emergency Operations standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 to decide if revisions are needed in the scope of this project in relation to P81 and FERC directives. This project is a comprehensive review of this set of EOP standards to ensure that the requirements are clear and unambiguous. Many of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process, and the standards were due for a comprehensive review. Suggestions for improvement, possible consolidation and for requirements to be considered for retirement under Paragraph 81 have been submitted by stakeholders, other drafting teams and FERC staff.

On October 17, 2013 the Standards Committee accepted the recommendations of the EOP FYRT and appointed a drafting team to implement the recommendations and begin formal development. The Standards Committee further authorized the posting of the Standard Authorization Request (SAR) developed by the EOP FYRT.

Project 2009-03 – Emergency Operations (EOP-011-1) is being coordinated with Project 2008-02 – Undervoltage Load Shedding, which proposes to retire EOP-003-2 Requirements R2, R4, and R7 since these requirements are proposed to be covered by PRC-010-1, Requirement R1; this translation is illustrated in this document and will also be referenced in Project 2008-02's mapping document. The project schedules and implementation plans for these two projects are being closely coordinated to ensure that no gaps or duplication will result from the products developed by the two drafting teams.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R2. Each Transmission Operator and Balancing Authority shall: **R2.1.** Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity. **R2.2.** Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system. **R2.3.** Develop, maintain, and implement a set of plans for load shedding	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include: **R3.1.** Communications protocols to be used during emergencies. **R3.2.** A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.	Translated to EOP-011-1, Emergency Operations; Retired R3.1 under Criteria A and B7 of Paragraph 81 guidelines; Retired R3.4 under Criteria A and B1 of Paragraph 81 guidelines.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities. **R3.4.** Staffing levels for the emergency.		1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. **Retirements:** **Requirement R3.1** • Meets Criterion B7 and Criterion A of Paragraph 81; • Covered by EOP-001-2.1b Requirement R4 in Attachment 1 (proposed Requirements R1 and R2 in EOP-011-1); and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		• COM-001 and COM-002 are descriptive in the identification of protocols to use and, thus, adequately cover the generic reference. **Requirement R3.2** • Meets Criterion B7 and Criterion A of Paragraph 81; and • Load reduction within timelines is covered by BAL-002 Requirement R2. **Requirement R3.4** • Meets Criterion B1 of Paragraph 81; and • Staffing levels are administrative in nature.
R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2**

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.		reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to the Reliability Coordinator within a time period specified by its Reliability Coordinator. [Violation Risk Factor: High] [Time Horizon: Operation Planning] In this industry it is widely understood that "maintain," is not simply to establish the plan. The intent of the EOP SDT is for BAs and TOPs to keep its Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies contemporary and for the Emergency Plan to stay contemporary.
R6. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:	Retired under Criteria B6 and B7 of P81 guidelines.	**<u>Retirements</u>** **Requirement R6.1** • Meets Criterion B7 of Paragraph 81; and • Redundant with COM-001.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R6.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems. **R6.2.** The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used. **R6.3.** The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.) **R6.4.** The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.		**Requirement R6.2** • Meets Criterion B6 of Paragraph 81; • Speaks to an action to be taken during capacity issues that is not feasible in accomplishing; and • Transaction arrangements are a commercial practice. **Requirement R6.3** • Meets Criterion B7 of Paragraph 81; and • Covered by EOP-001-2.1b Requirement R4 in Attachment 1 (proposed Requirements R1 and R2 in EOP-011-1). **Requirement R6.4** • Meets Criterion A of Paragraph 81; and • Does not provide benefit to the reliability of the BES.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.	Retired under Criteria A and B7 of P81 guidelines.	**Retired – redundant with PER-001, R1 with respect to the Balancing Authority and IRO-001-1.1, Requirement R3 for the Reliability Coordinator.**
R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan to reduce risks to the interconnected system.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s);

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]* To have a TOP or BA contact other TOPs and BAs takes them away from the Emergency at hand, plus they do not have a wide-area view. The RC can give an indication

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		of impact and make high-level determinations. The RC has the wide-area overview and can quickly determine impacts of neighboring TOPs, BAs and RCs. The RC is to make contact within 30 minutes of notification. From there, IRO-005, IRO-006 and IRO-007 would address the specific actions to be taken.
R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.	EOP-002-3.1, R5 maps to BAL-003-1, R1, R2, R3, and R4.	**BAL-003-1, R1** R1. Each Frequency Response Sharing Group (FRSG) or Balancing Authority that is not a member of a FRSG shall achieve an annual Frequency Response Measure (FRM) (as calculated and reported in accordance with Attachment A) that is equal to or more negative than its Frequency Response Obligation (FRO) to ensure that sufficient Frequency Response is provided by each FRSG or BA that is not a member of a FRSG to maintain Interconnection Frequency Response equal to or more negative than the Interconnection Frequency Response Obligation. **BAL-003-1, R2**

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		R2. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and uses a fixed Frequency Bias Setting shall implement the Frequency Bias Setting determined in accordance with Attachment A, as validated by the ERO, into its Area Control Error (ACE) calculation during the implementation period specified by the ERO and shall use this Frequency Bias Setting until directed to change by the ERO. **BAL-003-1, R3** R3. Each Balancing Authority that is a member of a multiple Balancing Authority Interconnection and is not receiving Overlap Regulation Service and is utilizing a variable Frequency Bias Setting shall maintain a Frequency Bias Setting that is: (1.1) Less than zero at all times, and (1.2) Equal to or more negative than its Frequency Response Obligation when Frequency varies from 60 [Hertz] Hz by more than +/- 0.036 Hz. **BAL-003-1, R4**

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		R4. Each Balancing Authority that is performing Overlap Regulation Service shall modify its Frequency Bias Setting in its ACE calculation, in order to represent the Frequency Bias Setting for the combined Balancing Authority area, to be equivalent to either: • the sum of the Frequency Bias Settings as shown on FRS Form 1 and FRS Form 2 for the participating Balancing Authorities as validated by the ERO, or • the Frequency Bias Setting shown on FRS Form 1 and FRS Form 2 for the entirety of the participating Balancing Authorities' areas.
R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: **R6.1.** Loading all available generating capacity. **R6.2.** Deploying all available operating reserve. **R6.3.** Interrupting interruptible load and exports.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R6.4. Requesting emergency assistance from other Balancing Authorities. **R6.5.** Declaring an Energy Emergency through its Reliability Coordinator; and **R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.		2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall: **R7.1.** Manually shed firm load without delay to return its ACE to zero; and **R7.2.** Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s);

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R6** R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated	Retired per P81 – this is addressed in NAESB tagging specification.	**LSEs have no Real-time reliability functionality with respect to EEAs.** Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Resources) to Priority 7 (Network Integration transmission Service from designated Network Resources) as permitted in its transmission tariff: **R9.1**. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts." **R9.2.** The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed. **R9.3.** The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7. **R9.4.** The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange		request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Transaction on the system from Priority 6 to Priority 7.		
Attachment 1 **2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.	Translated to EOP-011-1, Attachment 1.	**Attachment 1EEA 2 – Load management procedures in effect** • An energy deficient BA is still able to maintain minimum Contingency Reserve requirements. Using Contingency Reserves (which is a subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that the point where a BA can no longer maintain this important Contingency Reserves margin is a most serious condition and puts the BA into a position where they are very close to shedding Load ("imminent or in progress"). The drafting team felt that this warrants categorization at the highest level of EEA. The previous language in EOP-002-3.1, EEA 2 used "Operating Reserve," which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently. Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using minimum Contingency Reserve in the language would eliminate some of the confusion. This is a different approach but the drafting team believes this is a good approach and was supported by several commenters.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.	EOP-003-2, R2 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design.	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2. The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels.	EOP-003-2, R4 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
	PC or TP is responsible for the program design. EOP-003-2, R4 is inherently embedded in PRC-010-1, R1, Part 1.1. The specific items noted are described in PRC-010-1's Guidelines and Technical Basis.	to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design. **1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.	Translated to EOP-011-1, Emergency Operations. Rehearing of FERC Order No. 763, Paragraph 11: *"Accordingly, we grant clarification that* ***Order No. 763 did not preclude some degree of overlap between automatic and manual load***	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
	shedding programs, provided there is sufficient non-overlapping load available for manual shedding to achieve the reliability objective of EOP-003-2."	1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon:

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions;

Exhibit E

Analysis of Violation Risk Factors and Violation Severity Levels

Project 2009-03: Emergency Operations

VRF and VSL Justifications for EOP-011-1

VRF and VSL Justifications – EOP-011-1, R1	
Proposed VRF	High
NERC VRF Discussion	Developing, maintaining and implementing a Reliability Coordinator-reviewed Operating Plan to provide the Transmission Operator the means to mitigate operating Emergencies in its Transmission Operator Area. This is a requirement that, if violated, could directly cause or contribute to Bulk Electric System (BES) instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. Since this requirement also is in the Operations Planning time frame, it could, if violated, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures; or could hinder restoration to a normal condition. Since this is a Requirement in a planning time frame, a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation or Cascading failures; or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the Operating Plan(s) and is consistent with Requirement R2.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-003-2 R1, which deals with Load shedding under Emergency conditions, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.

VRF and VSL Justifications – EOP-011-1, R1	
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to maintain it.
Proposed High VSL	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to have it reviewed by its Reliability Coordinator.
Proposed Severe VSL	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to implement it.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Operating Plan(s) is not developed, maintained and implemented.

VRF and VSL Justifications – EOP-011-1, R1	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to develop, maintain and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operating Area, failing to have it reviewed by its Reliability Coordinator, or failing to implement it for an Operating emergency.

VRF and VSL Justifications – EOP-011-1, R2	
Proposed VRF	High
NERC VRF Discussion	Developing, maintaining and implementing a Reliability Coordinator-reviewed Operating Plan provides the Balancing Authority the means to mitigate Capacity and Energy Emergencies. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. Since this requirement also is in the Operations Planning time frame, it could, if violated, under emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. Since this is a requirement in a planning time frame, a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the Operating Plan(s) and is consistent with Requirement R1.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-003-2 R1, which deals with Load shedding under Emergency conditions, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.

VRF and VSL Justifications – EOP-011-1, R2	
Proposed Lower VSL	N/A.
Proposed Moderate VSL	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to maintain it.
Proposed High VSL	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to have it reviewed by its Reliability Coordinator.
Proposed Severe VSL	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to implement it.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Operating Plan(s) is not developed, maintained and implemented.

VRF and VSL Justifications – EOP-011-1, R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to develop, maintain and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area or failing to have it reviewed by the Reliability Coordinator or failing to implement it for a Capacity or Energy Emergency.

VRF and VSL Justifications – EOP-011-1, R3	
Proposed VRF	Medium
NERC VRF Discussion	Review of an Operating Plan provides the Transmission Operator and Balancing Authority with a Wide Area coordination of their plans. Since this is a requirement in a planning time frame that a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control or restore the BES. However, violation of a medium-risk requirement is unlikely, under Emergency, abnormal or restoration conditions anticipated by the preparations, to lead to BES instability, separation or Cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement specifies that the Reliability Coordinator must review a Transmission Operator's and Balancing Authority's Operating Plans within 30 calendar days of receipt regarding any reliability risks that are identified between Operating Plans. Requirements R1 and R2 specify that the Transmission Operator and Balancing Authority must develop, maintain and implement a Reliability Coordinator-reviewed Operating Plan(s). Requirement R3 ties these three requirements together.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-006-2 R4, which requires the Reliability Coordinator to review neighboring Reliability Coordinator's restoration plans, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

VRF and VSL Justifications – EOP-011-1, R3	
Proposed High VSL	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.
Proposed Severe VSL	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Reliability Coordinator failed to review a Transmission Operator and Balancing Authority Operating Plans that it received regarding any reliability risks that are identified between Operating Plans within the specified time frame.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based	The VSL is assigned for a single instance of failing to review a Transmission Operator and Balancing Authority Operating Plans that it received regarding any reliability risks that are identified between Operating Plans within the specified time frame.

VRF and VSL Justifications – EOP-011-1, R3	
on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – EOP-011-1, R4	
Proposed VRF	High
NERC VRF Discussion	Addressing any reliability risks identified by the Reliability Coordinator during its review Plan provides the Transmission Operator or the Balancing Authority the opportunity to have a Wide-area view of its Operating Plan(s) and to address any risks that it may have overlooked. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. Since this requirement also is in the Operations Planning time frame, it could, if violated, under emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. Since this is a requirement in a planning time frame, a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This requirement specifies that revisions to the Operating Plan(s) be made to address any risks overlooked in the original Operating Plan(s). This requirement is consistent with Requirements R1 and R2 which requires that the Operating Plan(s) be developed, maintained and implemented.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-003-2 R1, which deals with Load shedding under Emergency conditions, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.

VRF and VSL Justifications – EOP-011-1, R4	
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.
Proposed Severe VSL	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Transmission Operator or Balancing Authority failed to update and resubmit the Operating Plan(s) to its Reliability Coordinator within the timeframe determined by its Reliability Coordinator, or if they simply failed to update and resubmit the Operating Plan(s) to the Reliability Coordinator.
FERC VSL G3	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – EOP-011-1, R4	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failure to update and resubmit the Operating Plan(s) to its Reliability Coordinator within the timeframe determined by the Reliability Coordinator, or if they simply failed to update and resubmit the Operating Plan(s) to its Reliability Coordinator.

VRF and VSL Justifications – EOP-011-1, R5	
Proposed VRF	High
NERC VRF Discussion	Notifying Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators of an Emergency helps other entities have proper situational awareness and allows them the opportunity to implement measures to mitigate the Emergency. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement specifies that the Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. This relates to Requirements R1 and R2, whereby the Transmission Operator and the Balancing Authority implement their Operating Plans. These Requirements are all assigned a High VRF.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-011-1 Requirements R1, Part 1.2.1 and Requirement R2, Part 2.2, are assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

VRF and VSL Justifications – EOP-011-1, R5	
Proposed High VSL	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.
Proposed Severe VSL	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if a Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, within 30 minutes from the time of receiving notification, other neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4	The VSL is assigned for a single instance of failing to notifying other entities within 30 minutes of receiving notification.

VRF and VSL Justifications – EOP-011-1, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – EOP-011-1, R6	
Proposed VRF	High
NERC VRF Discussion	Declaration of a potential or actual Energy Emergency alert helps other entities have proper situational awareness and allows them the opportunity to implement measures to mitigate the Energy Emergency. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement and Attachment 1 provide additional detail regarding the initiation of a potential or actual Energy Emergency. This links to Requirement R2, Part 2.2.2 regarding the criteria for an Energy Emergency alert. Both of these Requirements are assigned a High VRF
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-011-1 Requirement R2, Part 2.2.2, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency alert.

VRF and VSL Justifications – EOP-011-1, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area and fails to declare an NERC Energy Emergency alert, as detailed in Attachment 1.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of a Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area and fails to declare an NERC Energy Emergency alert, as detailed in Attachment 1.

Exhibit F

Analysis of Commission Directives

Project 2009-03 Emergency Operations (EOP-001-2.1b, -002-3.1, and -003-2)

Consideration of Issues and Directives | November 2014

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
P 561. (S- Ref 10063 – EOP-001) "As we noted in the NOPR, some control areas define and effectively use more than the "normal," "alert" and "emergency" system states included in the Blackout Report recommendation.**238** We proposed that the ERO determine the optimum number of system states to be employed continent-wide and to consider the addition of the restoration state.**239** Accordingly, we direct the ERO to determine the optimum number of continent-wide system states and their attributes and to modify the Reliability Standard through the Reliability Standards development process to accomplish this objective."	FERC Order No. 693	Cautionary could be normal operations for one entity, while an emergency state for another entity. It is virtually impossible to define Emergency system states, as they are case specific. The intent of the EOP SDT is for the TOPs and BAs to identify, in Requirements R1 and R2, conditions that put them into an emergency state. So the EOP SDT believes that the directive is met with EOP-011-1 through an equally effective method. **R1.** Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **1.1.** Roles and responsibilities for activating the Operating Plan(s); **1.2.** Processes to prepare for and mitigate Emergencies including: **1.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; **1.2.2.** Cancellation or recall of Transmission and generation outages; **1.2.3.** Transmission system reconfiguration; **1.2.4.** Redispatch of generation request;

		1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **1.2.6.** Reliability impacts of extreme weather conditions. **R2.** Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **2.1.** Roles and responsibilities for activating the Operating Plan(s); **2.2.** Processes to prepare for and mitigate Emergencies including: **2.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; **2.2.2.** Requesting an Energy Emergency Alert, per Attachment 1; **2.2.3.** Managing generating resources in its Balancing Authority Area to address: **2.2.3.1.** capability and availability; **2.2.3.2.** fuel supply and inventory concerns; **2.2.3.3.** fuel switching capabilities; and **2.2.3.4.** environmental constraints. **2.2.4.** Public appeals for voluntary Load reductions; **2.2.5.** Requests to government agencies to implement their programs to achieve necessary energy reductions;

		2.2.6. Reduction of internal utility energy use; **2.2.7.** Use of Interruptible Load, curtailable Load and demand response; **2.2.8.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **2.2.9.** Reliability impacts of extreme weather conditions.
P 562. (S- Ref 10064 – EOP-001) "Further, we agree with ISO-NE that the proposed modification should be fieldtested and that policies and procedure be put in place, including operator training, before any processes for continent-wide system states are implemented. Such testing will help assure that all applicable entities and their personnel understand how the terms will be used and will allow operators to train staff to make any necessary changes to their policies and procedures. We direct the ERO to consider such a pilot program as it modifies EOP-001-0 through the Reliability Standards development process."	FERC Order No. 693	The EOP SDT concluded that to run a "fieldtest" would not be a viable option with Emergency states, as one would not intentionally create an Emergency state on the System just to see if it can recover. The EOP SDT concluded that the currently-enforced PER-005-1 standard addresses Emergency operations training for Reliability Coordinators, Balancing Authorities and Transmission Operators: **R3.** At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel. *[Violation Risk Factor: Medium] [Time Horizon: Long-term Planning]* **R3.1.** Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions.

P 571 (S- Ref 10066 – EOP-002) “As we stated in the NOPR, neither EOP-002-2 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies. The Commission agrees with MRO that “insufficient transmission capability” could be due to various causes. The ERO should examine whether to clarify this term in the Reliability Standards development process.”	FERC Order No. 693	The EOP SDT has included transmission related items to be included in the Transmission Operator’s Emergency Operating Plan(s). These items impact transmission capability and include Requirement R1, Parts 1.2.2-1.2.4: 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request;
573 (S- Ref 10067 – EOP-003) “The Commission agrees with FirstEnergy that for demand-side resources to qualify as another tool for balancing authorities to use in meeting control performance and disturbance control Reliability Standards, they must meet comparable technical performance requirements as generation resource options. In response to comments from Comverge and APPA, the Commission believes that curtailable loads are adequately addressed in Requirement R6 of the Reliability Standard but that demand response is not covered. Demand response covers considerably more resources than interruptible load. Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically	FERC Order No. 693	The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT developed individual requirements for the Transmission Operator and the Balancing Authority to develop, maintain and implement Operating Plan(s) to mitigate operating Emergencies. The requirements incorporate the applicable elements of Attachment 1 for each entity. **R3.** Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **3.1.** Roles and responsibilities for activating the Operating Plan(s); **3.2.** Processes to prepare for and mitigate Emergencies including: **3.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; **3.2.2.** Cancellation or recall of Transmission and generation outages; **3.2.3.** Transmission system reconfiguration;

feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements.”		**3.2.4.** Redispatch of generation request; **3.2.5.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **3.2.6.** Reliability impacts of extreme weather conditions. **R4.** Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **4.1.** Roles and responsibilities for activating the Operating Plan(s); **4.2.** Processes to prepare for and mitigate Emergencies including: **4.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; **4.2.2.** Requesting an Energy Emergency Alert, per Attachment 1; **4.2.3.** Managing generating resources in its Balancing Authority Area to address: **4.2.3.1.** capability and availability; **4.2.3.2.** fuel supply and inventory concerns; **4.2.3.3.** fuel switching capabilities; and **4.2.3.4.** environmental constraints. **4.2.4.** Public appeals for voluntary Load reductions;

		4.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; **4.2.6.** Reduction of internal utility energy use; **4.2.7.** Use of Interruptible Load, curtailable Load and demand response; **4.2.8.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **4.2.9.** Reliability impacts of extreme weather conditions.
595 (S- Ref 10072 – EOP-003) "The Commission concludes that the Reliability Standard needs to be modified to ensure that adequate load shedding capabilities are provided so that system operators have an effective operating measure of last resort to contain system emergencies and prevent cascading. The Commission recognizes that the amount of load shedding capability required is dependent on system characteristics and therefore it may not be feasible to have a uniform nationwide load shedding capability. This, however, does not preclude a uniform nationwide criterion on the methodology for establishing load shedding capability that would specify the minimum	FERC Order No. 693	The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT developed individual requirements for the Transmission Operator and the Balancing Authority to develop, maintain and implement Operating Plan(s) to mitigate operating Emergencies. The requirements incorporate the applicable elements of Attachment 1 for each entity. **R1.** Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **1.1.** Roles and responsibilities for activating the Operating Plan(s); **1.2.** Processes to prepare for and mitigate Emergencies including: **1.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; **1.2.2.** Cancellation or recall of Transmission and generation outages;

amount of load shedding capability that should be provided based on system characteristics and conditions and the maximum amount of delay before load shedding can be implemented. The Commission directs the ERO to address the minimum load and maximum time concerns of the Commission through the Reliability Standards development process. We suggest that a review of industry best practices would be useful in developing nationwide critera.		**1.2.3.** Transmission system reconfiguration; **1.2.4.** Redispatch of generation request; **1.2.5.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **1.2.6.** Reliability impacts of extreme weather conditions. **R2.** Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **2.1.** Roles and responsibilities for activating the Operating Plan(s); **2.2.** Processes to prepare for and mitigate Emergencies including: **2.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; **2.2.2.** Requesting an Energy Emergency Alert, per Attachment 1; **2.2.3.** Managing generating resources in its Balancing Authority Area to address: **2.2.3.1.** capability and availability; **2.2.3.2.** fuel supply and inventory concerns; **2.2.3.3.** fuel switching capabilities; and

		2.2.3.4. environmental constraints. **2.2.4.** Public appeals for voluntary Load reductions; **2.2.5.** Requests to government agencies to implement their programs to achieve necessary energy reductions; **2.2.6.** Reduction of internal utility energy use; **2.2.7.** Use of Interruptible Load, curtailable Load and demand response; **2.2.8.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **2.2.9.** Reliability impacts of extreme weather conditions.
P 597 (S- Ref 10073 – EOP-003) and Paragraph 603 "As suggested by California PUC, periodic drills of simulated load shedding should involve all participants required to ensure successful implementation of load shedding plans. As such, the drills should extend beyond system operators to distribution operators and LSEs. The Reliability Standard should require periodic drills by entities subject to section 215, and require those entities to seek participation by other entities. The drills should test the readiness and functionality of the load shedding plans,	FERC Order No. 693	Directive is addressed by several currently-effective Reliability Standards, including EOP-006-2 – System Restoration Coordination, and PER-005-1 – Operations Personnel Training. Currently-effective Reliability Standard EOP-006-2, Requirement R10 addresses periodic drills and provides: R10. Each Reliability Coordinator shall conduct two System restoration drills, exercises, or simulations per calendar year, which shall include the Transmission Operators and Generator Operators as dictated by the particular scope of the drill, exercise, or simulation that is being conducted. R10.1. Each Reliability Coordinator shall request each Transmission Operator identified in its restoration plan and each Generator Operator identified in the Transmission Operators' restoration plans to participate in a drill, exercise, or simulation at least every two calendar years.

including, at times, the actual deployment of personnel. Therefore the Commission disagrees with FirstEnergy that the requirement for periodic drills of simulated load shedding should be incorporated into the new PER-005-0 Reliability Standard that is currently being drafted to address operator training."		Requirement R3 of currently-effective Reliability Standard PER-005-1 provides: R3. At least every 12 months each Reliability Coordinator, Balancing Authority and Transmission Operator shall provide each of its System Operators with at least 32 hours of emergency operations training applicable to its organization that reflects emergency operations topics, which includes system restoration using drills, exercises or other training required to maintain qualified personnel. R3.1. Each Reliability Coordinator, Balancing Authority and Transmission Operator that has operational authority or control over Facilities with established IROLs or has established operating guides or protection systems to mitigate IROL violations shall provide each System Operator with emergency operations training using simulation technology such as a simulator, virtual technology, or other technology that replicates the operational behavior of the BES during normal and emergency conditions. While not explicitly included, the training required by PER-005-1 (and included in Requirement R4 of future-effective Reliability Standard PER-005-2) could include simulated load shedding.
P 601 (S- Ref 10074 – EOP-003) "APPA Comments are in Paragraph 598: 'In addition, APPA states that NERC should consider requiring balancing authorities and transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners'."	FERC Order No. 693	The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT developed individual requirements for the Transmission Operator and the Balancing Authority to develop, maintain and implement Operating Plan(s) to mitigate operating Emergencies. The requirements incorporate the applicable elements of Attachment 1 for each entity. Coordination and planning of automatic and manual Load shedding has been adequately addressed by requiring Transmission Operators and Balancing Authorities to have a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies. **R1.** Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s)

Exhibit G

Summary of Development History and Complete Record of Development

EXHIBIT G

Summary of Development History

The development record for the proposed Reliability Standard EOP-011-1 is summarized below.

I. Overview of the Standard Drafting Team

When evaluating a proposed Reliability Standard, the Commission is expected to give "due weight" to the technical expertise of the Electric Reliability Organization ("ERO").[1] The technical expertise of the ERO is derived from the standard drafting team. For this project, the standard drafting team consisted of industry experts, all with a diverse set of experiences. A roster of the standard drafting team members is included in **Exhibit H**.

II. Standard Development History

A. Five-Year Review Recommendations

A review team was assembled to conduct a five-year review of Emergency Operations Reliability Standards EOP-001-2.1b, EOP-002-3.1, and EOP-003-2. Recommendations of the Emergency Operations Five Year Review Team ("EOP FYRT") were posted for a formal comment period from August 6, 2013 to September 19, 2013, and upon consideration of these comments, the EOP FYRT submitted the recommendations to the Standards Committee for review.

B. Standard Authorization Request Development

The Standard Authorization Request ("SAR") for addressing the findings of the EOP FYRT related to Emergency Operations Reliability Standards submitted to the Standards Committee. The SAR was originally posted as part of Project 2009-03 for public comment from November 6, 2013 to December 5, 2013, and there were 34 comments to the posting of the SAR from a variety of industry participants, individuals, and organizations.

Based on the recommendations of the EOP FYRT, applicable FERC directives, and

Paragraph 81 Criteria, the Emergency Operations Standard Drafting Team ("EOP SDT") proposed to consolidate EOP-001-2.1b, EOP-002-3.1, and EOP-003-2 into proposed Reliability Standard EOP-011-1—Emergency Operations.

C. The First Posting – Informal Comment Period

The first draft of proposed Reliability Standard EOP-011-1 was posted for an informal 30-day public comment period from March 28, 2014 to April 28, 2014. There were 40 sets of comments, including comments from approximately 131 different people from approximately 88 companies representing all 10 industry segments.

Based on industry comments the drafting team made the following modifications to the proposed standard and associated documents:

- Added a clause to the Requirement R1 Rationale stating that if any part of Requirement R1 is not applicable, then the Transmission Operator should note that the entity is "not applicable" in its plan.
- Made minor clarifications, updates, additions, and deletions to parts of Requirement R1.
- Added the term "Operator-controlled" before "manual Load shedding" in Requirement R1, Part 1.2.6 and Requirement R2, Part 2.4.8 as it was in EOP-003-2, Requirement R8.
- Added details to the Requirement R2 rationale mandating that if any Requirement R2 Parts are not applicable, that the Balancing Authority should note that the entity is "not applicable" in its plan.
- Made minor clarifications, updates, additions, and deletions to parts of Requirement R2.
- Deleted Requirement R3 to remove the responsibility of the Reliability Coordinator to coordinate the Emergency Operating Plans of the entities in its Reliability Coordinator Area.
- Added language to Requirement R1, Part 1.3 and Requirement R2, Part 2.5 to ensure coordination of Emergency Operation Plans with "impacted" Transmission Operators and Balancing Authorities.
- Deleted Requirement R5 because it is parallel to existing Reliability Standard TOP-001-1a.
- Added the following language to Requirement R1, Part 1.2.1: "Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an Operating Emergency."
- Added language to Requirement R2, Part 2.2 to require notification to the Reliability Coordinator to include current and forecasted conditions, when experiencing a Capacity Emergency or Energy Emergency.
- Deleted Requirement R6.
- Replaced the word "practicable" with "practical" in Requirement R7 to provide clarity to

the intent of the drafting team.

- Removed the "Load Serving Entity" as an applicable entity in Requirement R9 and removed "NERC" from "Energy Emergency alert" in Requirement R9.
- Restored the previous three alert levels of Attachment 1 and revised the levels based on industry comments and collaboration with the standard drafting team for BAL-002.
- Included several minor clarification edits to various Requirements within EOP-011-1.

D. The Second Posting – Formal Comment Period and Initial Ballot

The second draft of proposed Reliability Standard EOP-011-1 was posted for a formal 30-daycomment period from July 2, 2014 to August 15, 2014, with an initial ballot held from August 6, 2014 to August 15, 2014. The standard drafting team received 56 sets of comments, including comments from approximately 174 different people from approximately 120 companies representing 9 of the 10 industry segments. The initial ballot achieved a 77.66% quorum and an approval of 42.27%; therefore, it did not receive sufficient affirmative votes for approval. The non-binding poll of the associated Violation Risk Factors and Violation Severity Levels achieved a quorum of 77.37% and an approval of 42.23%.

Based on industry comments the drafting team made the following modifications to the proposed standard and associated documents:

- Made clarifying changes to the Requirements R1.2.6 and R2.4.8.
- Removed the term "Emergency" from "Emergency Operating Plan."
- Added the term "not applicable" to Requirements R1 and R2 where the prior version reflected this intent by the SDT within the rationale box.
- Deleted Requirements R1.3 and R2.5.
- Redrafted Requirement R3 to have the Reliability Coordinator review and determine reliability risks that exist between Transmission Operators and Balancing Authorities within its Reliability Coordinator Area and to have the Reliability Coordinator look for potential reliability risks between multiple plans.
- Created Requirement R4 to require impacted Balancing Authorities or Transmission Operators to correct their plans within a timeframe specified by the Reliability Coordinator and resubmit the plans.
- Deleted Section 3.2 in the Attachment 1 to ensure that the industry does not shed load in order to maintain reserves.
- Modified the "Circumstances" of EE3 of Attachment 1 to state that "[t]he energy deficient BA is unable to meet minimum Contingency Reserve requirements," and modified the "Title" of EE3 by eliminating the words "Inability to meeting

Operating Reserve requirement or…"

- Modified the "Circumstances" for EEA2 of Attachment 1 that show that an entity will be in this level when it has implemented its Operating Plan to mitigate Emergencies but is still able to maintain Contingency reserves.
- Added the Time Horizon "Long-term Planning" to Requirements R1 and R2.
- Modified the VSL of Requirements R3, R4, and R5.
- Modified the standard so that Load is not shed to maintain reserves, and removed the requirement to have the Operating Plans approved by the Reliability Coordinator.
- Removed the term "System" from the notification process in Requirements R1 and R2.
- Replaced the term "Strategies" with "Processes" in Requirements R1 and R2.
- Replaced the term "requesting BA" in Attachment 1 with "energy deficient BA."
- Removed the term "voltage control" from the requirements.
- Modified the term "Emergency Operating Plan" to "Operating Plan to mitigate Emergencies" throughout the Standard.
- Made other various changes to the Standard to provide clarity.

E. Third Posting – Formal Comment Period and Additional Ballot

The third draft of proposed Reliability Standard EOP-011-1 and the newly proposed definition of "Energy Emergency" in the NERC Glossary of Terms were posted for a formal 30-day comment period from September 5, 2014 to October 20, 2014, with an additional ballot held from October 10, 2014 to October 20, 2014. The ballot achieved a quorum of 80.93% and an approval of 70.41%; therefore, the proposed standard and definition achieved a quorum and received sufficient affirmative votes for approval. The non-binding poll of the associated Violation Risk Factors and Violation Severity Levels achieved a quorum of 80.12% and an approval of 70.23%.

Based on industry comments the drafting team made the following modifications to the proposed standard, the new definition, and associated documents:

- Changed "Plan" to "Plan(s)" throughout the standard to reiterate the drafting team's intent that reference to "Operating Plan" could refer to one plan or multiple plans.
- Provided additional clarification and detail to Requirement R2, Part 2.2.3, and Requirement R3, Parts 3.1 and 3.1.3.
- Revised Attachment 1 to replace "adjacent" with "neighboring" and to provide minor clarifications.

- Removed the Rationale box from Requirement R6 as it was incorrect and misplaced.
- Removed the term “impacted” from Requirement R5 High/Severe VSL for consistency with the changes made to Requirement R5.
- Updated the Technical Justification to the then-current revisions of EOP-011-1.
- Provided clarification to Compliance Section C, Compliance Monitoring and Assessment Processes.
- Made various changes to the Standard to provide clarity and to correct suggested punctuation, grammar, and syntax errors where merited.

F. Fourth Posting – Final Ballot

The fourth and final ballot for the Reliability Standard and definition were conducted from October 28, 2014 to November 6, 2014. The final ballot achieved a quorum of 87.19% and an approval of 73.20%; therefore, the Reliability Standard and definition achieved a quorum and received sufficient affirmative votes for approval.

G. Board of Trustees Approval

Reliability Standard EOP-011-1 and the definition of “Energy Emergency” were approved by the NERC Board of Trustees on November 13, 2014.

Project 2009-03 Emergency Operations

Related Files

Status:

Adopted by the NERC Board of Trustees November 13, 2014 and pending regulatory approval.

Background:

The EOP SDT merged previous standards (EOP-001-2.1b, EOP-002-3.1 and EOP-003-2) to create EOP-011-1. The revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities. In addition, the revisions are intended to streamline the standard and apply Paragraph 81 criteria, while making the standard more results-based and addressing outstanding directives from FERC Order No. 693.

Draft	Action	Dates	Results	Consideration of Comments
Final Draft **EOP-011-1 Emergency Operations** Clean **(91)** | Redline to Last Posted **(92)** **Implementation Plan** Clean **(93)** | Redline to Last Posted **(94)** **Supporting Documents:** Summary of Changes **(95)** **VRF/VSL Justification** Clean **(96)** | Redline to Last Posted **(97)**	Final Ballot Info>> **(107)** Vote>>	10/28/14 – 11/06/14 (closed)	Summary>> **(108)** Ballot Results>> **(109)**	

Issues and Directives Clean **(98)** | Redline to Last Posted **(99)** Analysis of Impacts of Proposed Revision to Defined Term **(100)** **Mapping Document** Clean **(101)** | Redline to Last Posted **(102)** Technical Background and Rationale **(103)** Standard Authorization Request **(104)** **Proposed Definitions for the NERC Glossary of Terms** Clean **(105)** | Redline to Last Posted **(106)**				
Draft 3 **EOP-011-1 Emergency Operations** Clean **(69)** | Redline to Last Posted **(70)**	Additional Ballot and Non-binding Poll Info>> **(84)** Vote>>	10/10/14 - 10/20/14 (closed)	Summary>> **(86)** Ballot Results>> **(87)** Non-Binding Poll	Consideration of Comments>> **(90)**

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Clean (71) | Redline to Last Posted (72)

Supporting Documents:

Unofficial Comment Form (Word) (73)

VRF/VSL Justification (74)

Issues and Directives (75)

Analysis of Impacts of Proposed Revision to Defined Term (76)

Mapping Document (77)

Technical Background and Rationale (78)

Standard Authorization Request (79)

Proposed Definitions for the NERC Glossary of Terms
Clean (80) | Redline (81)

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EOP-011-1 Emergency Operations

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Implementation Plan (51)

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VRF/VSL Justification (53)

Issues and Directives (54)

Analysis of Impacts of Proposed Revision to Defined Term (55)

Mapping Document (56)

Technical Background and Rationale (57)

Standard Authorization Request (58)</td>
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Info>> (60)

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EOP-011-1 Emergency Operations **(40)** **Supporting Documents:** Standard Authorization Request **(41)** Unofficial Comment Form (Word) **(42)** Analysis of Impacts of Proposed Revision to Defined Term **(43)** Mapping Document **(44)** Technical Background and Rationale **(45)**				
Standard Authorization Request **(33)** **Supporting Documents:** Unofficial Comment Form (Word) **(34)** **Proposed Redlines to Standards:** EOP-001-3 **(35)** EOP-002-4 **(36)**	Comment Period Info>> **(38)** Submit Comments>>	11/06/13 - 12/05/13 (closed)	Comments Received>> **(39)**	

EOP-003-3 **(37)**				
Final Recommendation to Standards Committee Review of EOP-001-2.1b **(23)** Review of EOP-002-3.1 **(24)** Review of EOP-003-2 **(25)** SAR to Revise EOP-001, -002, and -003 **(26)** **Supporting Documents (to be attached to SAR)** **Proposed Redlines of Standards** Redline of EOP-001-2.1b **(27)** Redline of EOP-002-3.1 **(28)** Redline of EOP-003-2 **(29)** Outstanding Directives **(30)** Outstanding Issues **(31)** Review Team's Consideration of IERP	For Information			

Recommendations **(32)**				
Five-Year Review Recommendations Review of EOP-001-2.1b **(10)** Review of EOP-002-3.1 **(11)** Review of EOP-003-2 **(12)** **Supporting Documents** Outstanding Directives **(13)** Outstanding Issues **(14)** Paragraph 81 Criteria **(15)** Unofficial Comment Form **(16)** EOP-001-2.1b **(17)** EOP-002-3.1 **(18)** EOP-003-2 **(19)**	Comment Period Info>> **(20)** Submit Comments>>	08/6/2013 - 9/19/2013 (closed)	Comments Received>> **(21)**	Consideration of Comments>> **(22)**
SAR Clean **(8)** | Redline **(9)**	For Information Only	Last Modified 11/05/2010		

Supporting Material: Nomination Form (Word) **(6)**	SAR Drafting Team Nominations Submit Nomination>> Info>> **(7)**	12/7/2009 - 12/18/2009 (closed)		
Draft 1 SAR Emergency Operations SAR **(1)** **Supporting Material:** Comment Form (Word) **(2)**	Comment Period Submit Comment>> Info>> **(3)**	12/7/2009 - 1/15/2010 (closed)	Comments Received>> **(4)**	Consideration of Comments>> **(5)**

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard:	Emergency Operations (Project 2009-03)
Request Date:	October 30, 2009
SC Approval Date:	December 3, 2009

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name:	Al McMeekin	☐	New Standard
Primary Contact:	Al McMeekin	X	Revision to existing Standard
Telephone: **Fax:**	803-530-1963 803-957-4045	X	Withdrawal of existing Standard
E-mail:	al.mcmeekin@nerc.net	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

Applicable Standards:

- EOP-001-0 — Emergency Operations Planning
- EOP-002-2 — Capacity and Energy Emergencies
- EOP-003-1 — Load Shedding Plans
- IRO-001-1 — Reliability Coordination — Responsibilities and Authorities

The first three standards in the list above may be merged into a single standard. There are some requirements in IRO-001 that may be improved and merged into the new EOP standard.

The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The industry needs standards that are technically accurate and support the overall goal of ensuring bulk power system reliability. For the applicable entities to effectively comply, measurable and enforceable standards must be reasonable, clear and unambiguous minimizing the need for interpretation. Users, owners, and operators of the bulk power system should have no doubts with regards to what is required and who it is required of. Merging these standards will eliminate requirements that do not impact the bulk power system and remove redundant requirements.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

Many of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process; suggestions for improvement have been submitted by stakeholders, other drafting teams, and FERC staff. The drafting team will consider these comments throughout its review of the standards. Options for the proposed changes are to:

- Modify the requirement to improve its clarity and measurability while removing ambiguity,
- Move the requirement (into another SAR or Standard or to the certification process)
- Eliminate the requirement (either because it is redundant or because it doesn't support bulk power system reliability).

The standard drafting team will review the associated items in what is termed the "NERC Standards Issues Database (Issues Database)." The Issues Database is used by the NERC standards program staff to track the issues and concerns identified with a particular standard. Prior to the development of the Issues Database, the Standard Review Form was utilized to capture all issues referencing a particular standard. The Standard Review Forms and the Issues Database excerpts applicable to these standards are listed in (Attachment 1).

The standard drafting team will also review the assigned standards and modify them to conform to the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure as described in the "Global Improvements" section of Volume I of the *Reliability Standards Development*

Plan (Applicable sections of the Global Improvements section have been provided in Attachment2). This project will require the standard drafting team to coordinate with NAESB to ensure the reliability standard does not have any undue, adverse impact on business practices or competition, and to coordinate with the drafting teams that are already in place and have proposed requirements that interface with some of the EOP requirements (includes the Reliability Coordination SDT and the Operations Communications Protocols SDT). Additionally, FERC directives from Order 693 pertaining to these standards must be addressed.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.) This project involves reviewing and revising the four referenced standards: For each existing requirement, the drafting team will work with stakeholders and: - Eliminate redundancy in the requirements. - Identify requirements that should be moved. - Eliminate requirements that do not support bulk power system reliability. - Improve clarity and measurability, and remove ambiguity from the requirement. EOP-001-1, EOP-002-2, and EOP-003-1 were Version 0 standards with minimal updates. They each have requirements with applicabilities that are inconsistent with the functional model, as well as various words or elements that need clarification. IRO-001-1 has requirements with applicability and clarity issues that must be addressed and some requirements that may be moved to the new EOP standard(s). The Operations Communications Protocols SDT is working on a set of requirements for a new standard (COM-003-1) that references the use of Alert Levels, including those alert levels included in EOP-002-2. Close coordination between the two projects will be required. The Reliability Coordination SDT is working on a set of revisions to IRO-001-1 that includes retirement of several requirements. Close coordination between the two projects will be required.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
X	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
☐	Transmission Owner	Owns and maintains transmission facilities.
X	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
X	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
X	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
X	Generator Operator	Operates generation unit(s) to provide real and reactive power.
X	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
X	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
X	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
X	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
PER-002	Applicable personnel must be trained in restoration and blackstart procedures.
EOP-005	Contains TOP requirements for coordination of emergency plans with RC.
EOP-006	Contains RC requirements for coordination of emergency plans.

Related SARs

SAR ID	Explanation
Project 2007-02	Operations Communications Protocols SDT is working on a set of requirements for a new standard (COM-003-1) that references the use of Alert Levels, including those alert levels included in EOP-002-2.
Project 2006-06	The Reliability Coordination SDT is working on a set of revisions to IRO-001-1.

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

SAR for Project 2009-03 — Emergency Operations
Attachment 1

Relevant Issues from NERC Standards Issues Database

Source	Standard No.	Language
Frank Gaffney (FMPA) RSDP Input	EOP-001-0	The NERC Glossary of terms defines a TOP as: "the entity responsible for the reliability of its 'local' transmission system, and that operates or directs the operations of the transmission facilities." With this definition in mind, why is the TOP made responsible for EOP-001-1 R2.1: "develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity?"
Frank Gaffney (FMPA) RSDP Input	EOP-001-0	The NERC Glossary of terms defines a BA as: "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." In other words, responsible for supply and demand balance in the operating horizon. With this definition in mind, why is the BA responsible for EOP-001-1 R2.2 "Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system"?
Frank Gaffney (FMPA) RSDP Input	EOP-001-0	With regard to requirement R2, why is the BA responsible for Under Frequency Load Shedding (UFLS) when PRC-006-0 and PRC-007-0 make it the responsibility of the Regional Entities, the TOPs, the Distribution Providers and the LSEs? Why is the BA responsible for Under Voltage Load Shedding (UVLS) when the responsibility should probably be just the TOP's? Isn't this requirement redundant with PRC-006-0 and PRC-007-0?
Frank Gaffney (FMPA) RSDP Input	EOP-001-0	Requirement R4 (and by reference Attachment 1-EOP-001-0) is applicable to both the Transmission Operator and Balancing Authority but includes items that are not applicable to the TOP and are only applicable to the BA, e.g., why is a TOP responsible for fuel supply? Why is a TOP responsible for R6.2 concerning emergency energy? Why is a TOP responsible for fuel supply in R6.4, and why is the TOP responsible for arranging energy delivery?
Frank Gaffney (FMPA) RSDP Input	EOP-001-0	Requirement R2 of EOP-003-1 states: “Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.” The standards drafting team for Project 2007-01 Underfequency Load Shedding should consider modifying this requirement as part of their project.
Real-time Best Practices Standards Study Group	EOP-001-0	Establish document plans and procedures for conservative operations
FERC’s December 20, 2007 and April	EOP-002-2	On March 4, 2008, NERC submitted a compliance filing in response to a December 20, 2007 Order, in which the Commission reversed a NERC decision to register three retail power marketers to comply with Reliability Standards applicable to load serving entities (LSEs) and directed NERC to submit a plan describing how it would address a possible “reliability gap” that

4, 2008 Orders		NERC asserted would result if the LSEs were not registered. NERC's compliance filing included the following proposal for a short-term plan and a long-term plan to address the potential gap: · Short-term: Using a posting and open comment process, NERC will revise the registration criteria to define "Non-Asset Owning LSEs" as a subset of Load Serving Entities and will specify the reliability standards applicable to that subset. · Longer-term: NERC will determine the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers and process them through execution of the three-year Reliability Standards Development Plan. In this revised Reliability Standards Development Plan, NERC is commencing the implementation of its stated long-term plan to address the issues surrounding accountability for loads served by retail marketers/suppliers. The NERC Reliability Standards Development Procedure will be used to identify the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. Specifically, the following description has been incorporated into the scope for affected projects in this revised Reliability Standards Development Plan that includes a standard applicable to Load Serving Entities: Source: FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 Issue: In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the ReliabilityFirst (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: · FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf) · NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), · FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and · NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.
Real-time Best Practices Standards Study Group	EOP-003-1	Provide the location, Real-time status, and MWs of Load available to be shed.
FERC's December 20, 2007 and April 4, 2008 Orders	IRO-001-1	On March 4, 2008, NERC submitted a compliance filing in response to a December 20, 2007 Order, in which the Commission reversed a NERC decision to register three retail power marketers to comply with Reliability Standards applicable to load serving entities (LSEs) and directed NERC to submit a plan describing how it would address a possible "reliability gap" that NERC asserted would result if the LSEs were not registered. NERC's compliance filing included the following proposal for a short-term plan and a long-term plan to address the potential gap: · Short-term: Using a posting and open comment process, NERC will revise the registration criteria to define "Non-Asset Owning LSEs" as a subset of Load Serving Entities and will specify the reliability standards applicable to that subset. · Longer-term: NERC will determine the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers and process them through execution of the three-year Reliability Standards Development Plan. In this revised Reliability Standards Development Plan, NERC is commencing the implementation of its stated long-term plan to address the issues surrounding accountability for loads served by retail marketers/suppliers. The NERC Reliability Standards

		Development Procedure will be used to identify the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. Specifically, the following description has been incorporated into the scope for affected projects in this revised Reliability Standards Development Plan that includes a standard applicable to Load Serving Entities: Source: FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 Issue: In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the ReliabilityFirst (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: · FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf) · NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), · FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and · NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.

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Project 2009-03 — Emergency Operations</th></tr>
<tr><th colspan="2">Standard #</th><th>Title</th></tr>
<tr><td colspan="2">EOP-001-1</td><td>Emergency Operations Planning</td></tr>
<tr><td>Issues</td><td colspan="2">FERC Order 693
Disposition: Approved with modification
• Include reliability coordinators as an applicable entity.
• Consider Southern California Edison’s and Xcel’s suggestions in the standard development process.
• Clarify that the 30-minute requirement in requirement R2 to state that load shedding should be capable of being implemented as soon as possible but no more than 30 minutes.
• Includes definitions of system states (e.g. normal, alert, emergency), criteria for entering into these states. And the authority that will declare them.
• Consider a pilot program (field test) for the system states proposal.
• Clarifies that the actual emergency plan elements, and not the “for consideration” elements of Attachment 1, should be the basis for compliance.
V1 Industry Comments
• Combine R4 & R5
• Revise R5
• Measures are really data retention requirements
VRF comment
• R1 — primarily administrative
Other
• Modify standard to conform with the latest version of NERC’s Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure.</td></tr>
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Project 2009-03 — Emergency Operations</th></tr>
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<tr><td colspan="2">EOP-002-2</td><td>Capacity and Energy Emergencies</td></tr>
<tr><td>Issues</td><td colspan="2">FERC Order 693
Disposition: Approved with modification
• Address emergencies resulting not only from insufficient generation but also insufficient transmission capability, particularly as it affects the implement of the capacity and energy emergency plan.
• Include all technically feasible resource options, including demand response and generation resources
• Ensure the TLR procedure is not used to mitigate actual IROL violations.
V0 Industry Comments
• R3 should be applied to RC’s</td></tr>
</table>

	• Re-wording in R7 • Measures aren't really measures but requirements • L4 non-compliance needs definition of time frame • Several wording changes to Attachment • Compliance not mapped to requirements VRF comments • R10 — This is a commercial and administrative ordering of curtailments. Other • Modify standard to conform with the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure.

Standard Review Form Project 2009-03 — Emergency Operations	
Standard #	**Title**
EOP-003-1	Load Shedding Plans
Issues	FERC Order 693 Disposition: Approved with modification • Develop specific minimum load shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented based on overarching nationwide criteria that take into account system characteristics. • Require periodic drills of simulated load shedding. • Suggest a review of industry best practices in determining nationwide criteria. • Consider comments from APPA and ISO-NE in the standards development process. V0 Industry Comments • Move implementation requirements • Re-state purpose • Move to Policy 5 & 9 • Add UVLS VRF comments • R4 — Needs clarification • R6 — Failure to shed load in this condition can inhibit restoration. Other • Modify standard to conform with the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure.

SAR for Project 2009-03 — Emergency Operations
Attachment 2

Global Improvements

The standard drafting team is expected to review the assigned standards and modify the standards to conform to the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure as described in this "Global Improvements" section.

Statutory Criteria

In accordance with Section 215 of the Federal Power Act, FERC may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that "the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest."

The first three of these criteria can be addressed in large part by the diligent adherence to NERC's *Reliability Standards Development Procedure,* which has been certified by the ANSI as being open, inclusive, balanced, and fair. Users, owners, and operators of the bulk power system that must comply with the standards, as well as the end-users who benefit from a reliable supply of electricity and the public in general, gain some assurance that standards are just, reasonable, and not unduly discriminatory or preferential because the standards are developed through an ANSI-accredited procedure.

The remaining portion of the statutory test is whether the standard is "in the public interest." Implicit in the public-interest test is that a standard is technically sound and ensures a level of reliability that should be reasonably expected by end-users of electricity. Additionally, each standard must be clearly written, so that bulk power system users, owners, and operators are put on notice of the expected behavior. Ultimately, the standards should be defensible in the event of a governmental authority review or court action that may result from enforcing the standard and applying a financial penalty.

The standards must collectively provide a comprehensive and complete set of technically sound requirements that establish an acceptable threshold of performance necessary to ensure the reliability of the bulk power system. "An adequate level of reliability" would argue for both a complete set of standards addressing all aspects of bulk power system design, planning, and operation that materially affect reliability, and for the technical efficacy of each standard. The Commission directed NERC to define the term, "adequate level of reliability" as part of its January 18, 2007 Order on Compliance Filing. Accordingly, NERC's Operating and Planning Committees prepared the definition and the NERC Board approved it at its February 2008 meeting for filing with regulatory authorities. The NERC Standards Committee was then tasked to integrate the definition into the development of future reliability standards.

Quality Objectives

To achieve the goals outlined above, NERC has developed 10 quality objectives for the development of reliability standards. Drafting teams working on assigned projects are charged to ensure their work adheres to the following quality objectives:

1. **Applicability** — Each reliability standard shall clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted. Such functional classes[1] include: ERO, Regional Entities, reliability coordinators, balancing authorities, transmission operators, transmission owners, generator operators, generator owners, interchange authorities, transmission service providers, market operators, planning coordinators, transmission planners, resource planners, load-serving entities, purchasing-selling entities, and distribution providers. Each reliability standard that does not apply to the entire North American bulk power system shall also identify the geographic applicability of the standard, such as an interconnection, or within a regional entity area. The applicability section of the standard should also include any limitations on the applicability of the standard based on electric facility characteristics, such as a requirement that applies only to the subset of distribution providers that own or operate underfrequency load shedding systems.

2. **Purpose** — Each reliability standard shall have a clear statement of purpose that shall describe how the standard contributes to the reliability of the bulk power system.

3. **Performance Requirements** — Each reliability standard shall state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest. Each requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for bulk power system reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability** — Each performance requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement. Each performance requirement shall have one or more associated measures used to objectively evaluate compliance with the requirement. If performance results can be practically measured quantitatively, metrics shall be provided within the requirement to indicate satisfactory performance.

5. **Technical Basis in Engineering and Operations** — Each reliability standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.

6. **Completeness** — Each reliability standard shall be complete and self-contained. The standards shall not depend on external information to determine the required level of performance.

7. **Consequences for Noncompliance** — Each reliability standard shall make clearly known to the responsible entities the consequences of violating a standard, in

[1] These functional classes of entities are derived from NERC's Reliability Functional Model. When a standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in Reliability Standards.

combination with guidelines for penalties and sanctions, as well as other ERO and Regional Entity compliance documents.

8. **Clear Language —** Each reliability standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.
9. **Practicality —** Each reliability standard shall establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.
10. **Consistent Terminology —** Each reliability standard, to the extent possible, shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards Development Process.

In addition to these factors, standard drafting teams also contemplate the following factors the Commission uses to approve a proposed reliability standard as outlined in Order No. 672. A standard proposed to be approved:

1. **Must be designed to achieve a specified reliability goal**
   "321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of bulk power system facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to cyber security protection."

   "324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal. Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons."

2. **Must contain a technically sound method to achieve the goal**
   "324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal.

   Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons."

3. **Must be applicable to users, owners, and operators of the bulk power system, and not others**
"322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others."

4. **Must be clear and unambiguous as to what is required and who is required to comply**
"325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability."

5. **Must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation**
"326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply."

6. **Must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner**
"327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner."

7. **Should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect "best practices" without regard to implementation cost**
"328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently."

8. **Cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect bulk power system reliability**
"329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator"—if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability."

9. **Costs to be considered for smaller entities but not at consequence of less than excellence in operating system reliability**

"330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it."

10. **Must be designed to apply throughout North American to the maximum extent achievable with a single reliability standard while not favoring one area or approach**
"331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard."

11. **No undue negative effect on competition or restriction of the grid**
"332. As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another."

12. **Implementation time**
"333. In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability."

13. **Whether the reliability standard process was open and fair**
"334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the

ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission."

14. Balance with other vital public interests

"335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard."

15. Any other relevant factors

"323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed."

"337. In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. The Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed reliability standard."

Issues Related to the Applicability of a Standard

In Order No. 672, the Commission states that a proposed reliability standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the bulk power system must know what they are required to do to maintain reliability. Section 215(b) of the FPA requires all "users, owners and operators of the bulk power system" to comply with Commission-approved reliability standards.

The term "users, owners, and operators of the bulk power system" defines the statutory applicability of the reliability standards. NERC's Reliability Functional Model (Functional Model) further refines the set of users, owners, and operators by identifying categories of functions that entities perform so the applicability of each standard can be more clearly defined. Applicability is clear if a standard precisely states the applicability using the functions an entity performs. For example, "Each Generator Operator shall verify the reactive power output capability of each of its generating units" states clear applicability compared with a standard that states "a bulk power system user shall verify the reactive power output capability of each generating unit." The use of the Functional Model in the standards narrows the applicability of the standard to a particular class or classes of bulk power system users, owners, and operators. A standard is more clearly enforceable when it narrows the applicability to a specific class of entities than if the standard simply references a wide range of entities, e.g., all bulk power system users, owners, and operators.

In determining the applicability of each standard and the requirements within a standard, the drafting team should follow the definitions provided in the NERC Glossary of Terms Used in Reliability Standards and should also be guided by the Functional Model.

In addition to applying definitions from the Functional Model, the revised standards must address more specific applicability criteria that identify only those entities and facilities that are material to bulk power system reliability with regard to the particular standard.

The drafting team should review the registration criteria provided in the NERC Statement of Compliance Registry Criteria, which is the criteria for applicability. The registration criteria identify the criteria NERC uses to identify those entities responsible for compliance to the reliability standards. Any deviations from the criteria used in the Statement of Compliance Registry Criteria must be identified in the applicability section of the. It is also important to note that standard drafting teams cannot set the applicability of reliability standards to extend to entities beyond the scope established by the criteria for inclusion on NERC's Compliance Registry. This is expressly prohibited by Commission Order No. 693-A.

The goal is to place obligations on the entities whose performance will impact the reliability of the bulk power system, but to avoid painting the applicability with such a broad brush that entities are obligated even when meeting a requirement will make no material contribution to bulk power system reliability.

Every entity class described in the Functional Model performs functions that are essential to the reliability of the bulk power system. This point is best highlighted with the example that might be the most difficult to understand, the inclusion of distribution providers. Section 215 of the FPA specifically excludes facilities used in the local distribution of electric energy. Nonetheless, some of the NERC standards apply to a class of entities called Distribution Providers. Distribution Providers are covered because, although they own and operate facilities in the local distribution of electric energy, they also perform functions affecting and essential to the reliability of the bulk power system. With regard to these facilities and functions that are material to the reliability of the bulk power system, a distribution provider is a bulk power system user. For example, requirements for distribution providers in the reliability standards apply to the underfrequency load shedding relays that are maintained and operated within the distribution system to protect the reliability of the bulk power system. There are also requirements for distribution providers to provide demand forecast information for the planning of reliable operations of the bulk power system.

A similar line of thinking can apply to every other entity in the Functional Model, including Load-serving Entities and Purchasing-selling Entities, which are users of the bulk power system to the extent they transact business for the use of transmission service or to transfer power across the bulk power system. NERC has specific requirements for these entities based on how these uses may impact the reliability of the bulk power systems. Other functional entities are more obviously bulk power system owners and operators, such as Reliability Coordinators, Transmission Owners and Operators, Generator Owners and Operators, Planning Coordinators, Transmission Planners, and Resource Planners. It is the extent to which these entities provide for a reliable bulk power system or perform functions that materially affect the reliability of the bulk power system that these entities fall under the jurisdiction of Section 215 of the FPA and the reliability standards. The use of the Functional Model simply groups these entities into logical functional areas to enable the standards to more clearly define the applicability.

Issues Related to Regional Entities and Reliability Organizations

Because of the transition from voluntary reliability standards to mandatory reliability standards, confusion has occurred over the distinction between Regional Entities and Regional Reliability Organizations. The regional councils have traditionally been the owners and members of NERC. They have been referred to as Regional Reliability Organizations in the Functional Model and in the reliability standards. In an era of voluntary standards and guides, it was acceptable that a number of the standards included requirements for Regional Reliability Organizations to develop regional criteria, procedures, and plans, and included requirements for entities within the region to follow those requirements. Section 215 of the FPA introduced a new term, called “Regional Entity.” Regional Entities have specific delegated authorities, under agreements with NERC, to propose and enforce reliability standards within the region, and to perform other functions in support of the electric reliability organization. The former Regional Reliability Organizations have entered into delegation agreements with NERC to become Regional Entities for this purpose.

With regard to distinguishing between the terms Regional Reliability Organizations and Regional Entities, the following guidance should be used. The corporations that provide regional reliability services on behalf of their members are Regional Reliability Organizations. NERC may delegate to these entities a set of regional entity functions. The Regional Reliability Organizations perform delegated regional entity functions much like NERC is the organization that performs the ERO function. Regional Reliability Organizations may do things other than their statutory or delegated regional entity functions.

With the regions having responsibility for enforcement, it is no longer appropriate for the regions to be named as responsible entities within the standards. The plan calls for removing requirements from the standards that refer to Regional Reliability Organizations, either by deleting the requirements or redirecting the responsibilities to the most applicable functions in the Functional Model, such as Planning Coordinators, Reliability Coordinators, or Resource Planners. In instances where a regional standard or criteria are needed, the ERO may direct the Regional Entities to propose a regional standard in accordance with ERO Rule 312.2, which states NERC, may “direct regional entities to develop regional reliability standards.” There is no need to have a NERC standard that directs the regions to develop a regional standard. NERC standards should only include requirements for Regional Entities in those rare instances where the regions have a specific operational, planning, or security responsibility. In this case, Regional Entities (or NERC) may be noted as the applicable entity. However, these Regional Entities (or NERC) are held accountable for compliance to these requirements through NERC’s Rules of Procedure that, by delegation agreement, extend to the Regional Entities. The Regional Entities are not users, owners, or operators of the bulk power system and cannot be held responsible for compliance through the compliance monitoring and enforcement program. However, NERC and the Regional Entities can be held by the Commission to be in violation of its rules of procedure for failing to comply with the standards requirements to which it is assigned.

Issues Related to Ambiguity

Drafting teams should strive to remove all potential ambiguities in the language of each standard, particularly in the performance requirements. Redundancies should also be eliminated.

Specifically, each performance requirement must be written to include four elements:

- **Who** — defines which functional entity or entities are responsible for the requirements, including any narrowing or qualifying limits on the applicability to or of an entity, based on material impact to reliability.
- **Shall do what —** describes an action the responsible entity must perform.
- **To what outcome** — describes the expected, measurable outcome from the action.
- **Under what conditions** — describes specific conditions under which the action must be performed. If blank, the action is assumed to be required at all times and under all conditions.

Each requirement should identify a product or activity that makes a definite contribution to reliability.

Drafting teams should focus on defining measurable outcomes for each requirement, and not on prescribing *how* a requirement is to be met. While being more prescriptive may provide a sense of being more measurable, it does not add reliability benefits and may be inefficient and restrict innovation.

Issues Related to Technical Adequacy

In May 2006, the Commission issued an assessment on the then proposed reliability standards. The Commission noted under a “technical adequacy” section that requirements specified in some standards may not be sufficient to ensure an adequate level of reliability. While Order No. 672 notes that “best practice” may be an inappropriately high standard, it also warns that a “lowest common denominator” approach will not be acceptable if it is not sufficient to ensure system reliability.

Each standard should clearly meet the statutory test of providing an adequate level of reliability to the bulk power system. Each requirement should be evaluated and the bar raised as needed, consistent with good practice and as supported by consensus.

Issues Related to Compliance Elements

Each reliability standard includes a section to address measures and a section to address compliance. The Uniform Compliance Monitoring and Enforcement Guidelines, ERO Sanctions Guidelines, and Compliance Registry Criteria have been modified and have been approved by the Commission. As each standard is revised, or as new standards are developed, drafting teams need to familiarize themselves with these documents to ensure that each standard proposed for ballot is in a format that includes all the elements needed to support reliability and to ensure that the standard can be enforced for compliance.

The compliance-related elements of standards that may need to be modified to meet the latest approved versions of the various compliance documents noted above include the following:

- Each requirement must have an associated Violation Risk Factor.
- Each requirement must have an associated Time Horizon.
- The term, "Compliance Monitor" has been replaced with the term, "Compliance Enforcement Authority." Either the Regional Entity or the ERO may serve as the compliance enforcement authority. For most standards, the Regional Entity will serve as the compliance enforcement authority. In the situation where a Regional Entity has authority over a reliability coordinator, for example, the ERO will serve as the compliance enforcement authority to eliminate any conflict of interest.
- The eight processes used to monitor and enforce compliance have been assigned new names.
    - Compliance Audits
    - Self-Certifications
    - Spot Checking
    - Compliance Violation Investigations
    - Self-Reporting
    - Periodic Data Submittals
    - Exception Reporting
    - Complaints
- The audit cycles for various entities have been standardized so that the Reliability Coordinator, Transmission Operator, and Balancing Authority will undergo a routine audit to assess compliance with each applicable requirement once every three years while all other responsible entities will undergo a routine audit once every six years.
- Levels of Non-compliance have been replaced with "Violation Severity Levels."

All requirements are subject to compliance audits, self-certification, spot checking, compliance violation investigations, self-reporting and complaints. Only a subset of requirements is subject to monitoring through periodic data submittals and exception reporting.

Measures: While a measure can be used for more than one requirement, there must be at least one measure for each requirement. A measure states what a responsible entity must have or do to demonstrate compliance to a third party, i.e., the compliance enforcement authority. Measures are "yardsticks" used to evaluate whether required performance or outcomes have been achieved. Measures do not add new requirements or expand the details of the requirements. Each measure shall be tangible, practical, and objective. A measure should be written so that achieving full compliance with the measure provides the compliance monitor with the necessary and sufficient information to demonstrate that the associated requirement was met by the responsible entity. Each measure should clearly refer to the requirement(s) to which it applies.

Violation Severity Levels: The Violation Severity Levels (formerly known as Levels of Non-Compliance) indicate how severely an entity violated a requirement. Historically, there has been confusion about Levels of Non-Compliance. Some of the previously existing Levels of Non-Compliance incorporate reliability-related risk impacts or consequences. Going forward, the risk or consequences component should be addressed only by the Violation Risk Factor, while the Violation Severity Levels should only be used to categorize how badly the requirement was violated.

Criteria for determining which VSL to use:
It is preferable to have four VSLs representing a spectrum of performance, but where that does not work; the VSLs should be defensible in supporting the criteria in the table below.

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

Violation Risk Factors: Each drafting team is also instructed to develop a Violation Risk Factor for each requirement in a standard in accordance with the following definitions:

- **High Risk Requirement** — A requirement that, if violated, could directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures, or could place the bulk power system at an unacceptable risk of instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures, or could place the bulk power system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.

- **Medium Risk Requirement** — A requirement that, if violated, could directly affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk power system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

- **Lower Risk Requirement —** A requirement that is administrative in nature and, a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. A requirement that is administrative in nature; or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system.

Time Horizons: The drafting team must also indicate the time horizon available for mitigating a violation to the requirement:

- **Long-term planning —** a planning horizon of one year or longer.
- **Operations planning —** operating and resource plans from day ahead up to and including seasonal.
- **Same-day operations —** routine actions required within the timeframe of a day, but not real time.
- **Real-time operations —** actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations assessment —** follow-up evaluations and reporting of real time operations.

Note that some requirements occur in multiple time horizons, and it is acceptable to have more than one time horizon for a single requirement.

The drafting team should seek input and review of all measures and compliance information from the compliance elements drafting team members assigned to support each standard drafting team or from the NERC compliance staff.

Coordination with NAESB

Many of the existing NERC standards are related to business practices, although their primary purpose is to support reliability. Reliability standards, business practices, and commercial interests are inextricably linked.

It would be safe to conclude that every reliability standard has some degree of commercial impact and therefore impacts competition. The statutory test to be applied by the Commission is whether the reliability standard has an “undue adverse effect” on competition.

NERC has taken several steps to ensure its reliability standards do not have any undue, adverse impact on business practices or competition. First, NERC coordinates the development of all standards with the North American Energy Standards Board (NAESB). In addition to this formal process, drafting teams work with NAESB groups to ensure effective coordination of wholesale electric business practice standards and reliability standards. NERC and NAESB follow their procedure for the joint development of standards in areas that have both reliability and business practice elements. This procedure is being implemented for all standards in which the reliability and business practice elements are closely related, thereby making joint development a more efficient approach.

This project will require close coordination and joint development with NAESB as there are anticipated revisions to these standards that may need new or revised associated business practices.

To ensure each reliability standard does not have an undue adverse effect on competition, NERC requires that each standard meet the following criteria:

- Competition — A reliability standard shall not give any market participant an unfair competitive advantage.
- Market Structures — A reliability standard shall neither mandate nor prohibit any specific market structure.
- Market Solutions — A reliability standard shall not preclude market solutions to achieve compliance with that standard.
- Commercially Sensitive Information — A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.

During the standards development process, each Standards Authorization Request (SAR) drafting team asks the following question to determine if there is a need to develop a business practice associated with the proposed standard:

- Are you aware of any associated business practices that we should consider with this SAR?

Each standard drafting team also asks the following question to determine if there is a potential conflict between a reliability standard and business practice:

- Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement? If yes, please identify the conflict.

Additional Considerations
Drafting teams should consider the following in reviewing and revising their assigned standards:

- **Title**: In general, the title should be concise and to the point. Care should be taken not to try to fully describe a standard through its title. The title should fit a single line in both the header and in the body of the standard.
- **Purpose**: The purpose should clearly state a benefit to the industry (value proposition) in fulfilling the requirements. The purpose should not simply state “the purpose is to develop a standard to…” The purpose should be tied to one or more of the reliability principles.

- **References**: Section (F) provides a place to list associated references that support implementation of the standard. Drafting teams may develop or reference supporting documents with approval of the Standards Committee.
- **Version histories**: Version histories should be expanded to include complete listings of what has been changed from version to version so that end-users can easily keep track of changes to standards. This will also serve as a type of audit trail for changes.

Resource Documents Used

NERC used several references when preparing this plan. These references provide detailed descriptions of the issues and comments that need to be considered by the drafting teams, which are included in the second volume of the work plan, as they work on the standards projects defined in the plan. The references include:

- FERC NOPR on Reliability Standards, October 20, 2006.
- FERC Staff Preliminary Assessment of Proposed Reliability Standards, May 11, 2006.
- FERC Order No. 693 Mandatory Reliability standards for the Bulk Power System, March 16, 2007.
- FERC Order No. 693-A Mandatory Reliability Standards for the Bulk Power System, July 19, 2007.
- FERC Order No. 890 Preventing Undue Discrimination and Preference in Transmission Service, February 16, 2007.
- Comments of the North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment of Reliability Standards, June 26, 2006.
- Comments of the North American Electric Reliability Corporation on Staff Preliminary Assessment of NERC Standards CIP-002 through CIP-009, February 12, 2007.
- Comments of the North American Electric Reliability Corporation on the Notice of Proposed Rulemaking for Facilities Design, Connections and Maintenance Reliability standards, September 19, 2007.
- Comments received during the development of Version 0 reliability standards.
- Consideration of comments of the Missing Compliance Elements drafting team.
- Consideration of comments of the Violation Risk Factors drafting team.
- Consideration of comments in the Phase III–IV standards.
- Comments received during industry comment period on work plan.
- Q&A for Standards and Compliance.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form for Project 2009-03 Emergency Operations SAR

Please **DO NOT** use this form. Please use the electronic comment form located at the link below to submit comments on the proposed Emergency Operations SAR. Comments must be submitted by **January 15, 2010**. If you have questions please contact Al McMeekin at al.mcmeekin@nerc.net or by telephone at 803.530.1963

http://www.nerc.com/filez/standards/Project2009-03_Emergency_Operations.html

Background Information:
The SAR for Project 2009-03 Emergency Operations Project proposes modifications to the following standards:

- EOP-001-0 — Emergency Operations Planning
- EOP-002-2 — Capacity and Energy Emergencies
- EOP-003-1 — Load Shedding Plans
- IRO-001-1 — Reliability Coordination — Responsibilities and Authorities

Many of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process; suggestions for improvement have been submitted by stakeholders, other drafting teams, and FERC staff. The drafting team will consider these comments throughout its review of the standards. Options for the proposed changes include:

- Modify the requirement to improve its clarity and measurability while removing ambiguity,
- Move the requirement (into another SAR or Standard or to the certification process)
- Eliminate the requirement (either because it is redundant or because it doesn't support bulk power system reliability).

The standards do not meet some of NERC's quality objectives for reliability standards, and do not meet some of the factors FERC uses to determine whether to approve a standard as identified in FERC Order 672. The SAR proposes making modifications to bring the standards into conformance with these objectives and criteria.

The SAR proposes that the drafting team review the applicability of these standards and recommend modifications to align the applicability with the Functional Model. For example, in EOP-001, there Requirement R3.2 assigns both the Transmission Operator and the Balancing Authority the responsibility for having plans to mitigate operating emergencies on the transmission system – however the Balancing Authority isn't required to have the capability of monitoring and controlling the transmission system.

The SAR proposes adding clarity to the requirements where needed. For example, EOP-001, Requirement R1 includes a reference to "remote Balancing Authorities" – and some entities have indicated that the expectation for performance is not clear enough.

NERC has an obligation to address FERC's directives. It is the intent to identify all the applicable FERC directives in the SAR. There are several directives associated with load shedding – involving setting minimum load shedding criteria, requiring drills of simulated load shedding. Other stakeholders also indicated that more details are needed in requirements associated with load shedding.

The Real-time Best Practices team suggested that additional requirements should be added to require entities to have documented plans for conservative operations.

These are just some of the proposed modifications. Please review the SAR in its entirety and then answer the following questions by using the electronic comment form.

1. Do you agree that either there is a reliability-related need for the proposed standards action?

   ☐ Yes

   ☐ No

   Comments:

2. Do you agree with the scope of the proposed standards action?

   ☐ Yes

   ☐ No

   Comments:

3. Do you agree with the list of entities includes all those functional entities that may have one or more requirements assigned to them as part of this project? If not, please state specific reasons why not.

   ☐ Yes

   ☐ No

   Comments:

4. If you are aware of the need for a regional variance or business practice that we should consider with this SAR, please identify it here.

   Regional Variance:

   Business Practice:

   Comments:

5. If you have any other comments on this SAR that you have not already provided in response to the prior questions, please provide them here. Note that any comments recommending specific changes to the standards will be forwarded to the standard drafting team and will not be addressed by the SAR drafting team.

   Comments:

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Standards Authorization Request (SAR) Comment and Drafting Team Nomination Periods Open

Project 2009-03 Emergency Operations

Now available at: http://www.nerc.com/filez/standards/Project2009-03_Emergency_Operations.html

Nominations for SAR Drafting Team (through December 18, 2009)
The Standards Committee is seeking industry experts to serve on the Emergency Operations SAR Drafting Team (see project background below). The SAR drafting team will assist the requester in further developing the SAR and considering stakeholder comments.

If you are interested in serving on this SAR drafting team, please complete the following electronic nomination form **by December 18, 2009**: https://www.nerc.net/nercsurvey/Survey.aspx?s=f518d336e6d640188ab1e3c37099b8b6

Comment Period (through January 15, 2010)
The Standards Committee has posted a proposed SAR for a 30-day comment period **ending on January 15, 2010**.

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page (see project background below).

Project Background
This project involves reviewing and revising the following four standards to eliminate redundancy, identify requirements that should be moved, eliminate requirements that do not support bulk power system reliability, improve clarity and measurability, and remove ambiguity:

EOP-001 — Emergency Operations Planning
EOP-002 — Capacity and Energy Emergencies
EOP-003 — Load Shedding Plans
IRO-001 — Reliability Coordination — Responsibilities and Authorities

The three EOP standards may be merged into a single standard, and there are some requirements in IRO-001 that may be improved and merged into the new EOP standard. The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

The project will require close coordination with two other drafting teams. The Operations Communications Protocols drafting team is working on a set of requirements for a new standard (COM-003-1) that references the use of Alert Levels, including those alert levels included in EOP-002-2. The Reliability Coordination SDT is working on a set of revisions to IRO-001-1 that includes retirement of several requirements.

Project page: http://www.nerc.com/filez/standards/Project2009-03_Emergency_Operations.html

Standards Development Process
The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Individual or group. (20 Responses)
Name (12 Responses)
Organization (12 Responses)
Group Name (8 Responses)
Lead Contact (8 Responses)
Question 1 (20 Responses)
Question 1 Comments (20 Responses)
Question 2 (20 Responses)
Question 2 Comments (20 Responses)
Question 3 (18 Responses)
Question 3 Comments (20 Responses)
Question 4 (1 Responses)
Question 4 Comments (20 Responses)
Question 5 (0 Responses)
Question 5 Comments (20 Responses)

-	-
	Group
	Northeast Power Coordinating Council
	Guy Zito
	Yes
	Yes
	The SDT should not assume that the three EOP standards will be merged. EOP-001 deals with operational plans for both resource and transmission emergencies, whereas EOP-002 and EOP-003 deal with the actions needed in real-time to mitigate generation deficiency. EOP-001 is unique when compared with EOP-002, and EOP-003. Merging EOP-001 with the other two EOP standards will not result in gain in efficiency. The SDT should not assume that the three EOP standards will be merged. EOP-001 deals with operational plans for both resource and transmission emergencies, whereas EOP-002 and EOP-003 deal with the actions needed in real-time to mitigate generation deficiency. EOP-001 is unique when compared with EOP-002, and EOP-003. Merging EOP-001 with the other two EOP standards will not result in a gain in efficiency.
	Yes
	Group
	Bonneville Power Administration
	Denise Koehn
	Yes
	Yes
	a. Agree with the idea of merging EOP-001-0, EOP-002-2, and EOP-003-1 into a single Standard. b. Requirement 8 from IRO-001-1 should be included in a new single EOP standard and removed from IRO-001-1. This would allow IRO-001-1 to apply only to Reliability Coordinators and Regional Reliability Organizations. c. BPA supports improving clarity and removing redundant and non essential requirements (those that don't support bulk power system reliability.
	Yes
	a. In the paragraph under Industry Need, page SAR-2, suggest that the first sentence be rewritten to state as follows: "The industry needs standards that are technically accurate, clearly written so as to leave no confusion as to what a requirement means, and support the overall goal of ensuring bulk power system reliability". One concern with the EOP standards - and others - is the lack of use of the defined terms - with appropriate capitalization - from the NERC Glossary of Terms Used in Reliability Standards. The use of these terms without appropriate capitalization leads to confusion as to whether the words in the requirement mean something different than the defined term. b. On page SAR-10 The EOP-002-2 the comment from FERC about not using the TLR procedure to mitigate IROL violations doesn't seem right. IS FERC saying to allow an IROL to be VIOLATED (TOP-004 R1) by not changing phase shifters

	or ATC corrections or etc, so that a deficient entity won't be forced to shed load under a EEA? EOP-001 R2 says to have load reduction available to mitigate IROL. Or do they mean re-evaluate the IROL limits first which is already in the standard? In Attachment 2, page SAR-12, paragraph 3, suggest rewording 2nd sentence to say "Additionally, each standard must be clearly written, so that bulk power system users, owners, and operators are informed of the expected behavior (or have knowledge of the expected behavior, rather than "put on notice").
	Individual
	Jonathan Appelbaum
	Long Island Power Authority
	Yes
	Yes
	Yes
	These comments are for the SDT. Refernce is to existing standards: 1)EOP-001 R2.3 requires plans for load shedding and so does EOP-003 2) EOP-001 R2 and R3 can be merged. 3) EOP-001 R6 - Uses the term "coodinate with other...as appropriate". How is "appropriate"determined. Suggest tie it in with existin R3.3. 4) EOP-001 R6.3 - Consider eliminating because its literal meaning means in an emergency do one or the other, not both, and nothing else. 5) EOP-001 R6.4 - Transmission Operators do not arrange for fuel deliveries to Generators. What does aranging for electrical energy through normal operating channels mean? If its an emergency, can there be an Emergency communication protocol? 6)EOP-003 R2 and R3 - Eliminate. The under frequncy load shed program is developed by the Regional Entity in PRC-006. 7) EOP-003 R5 - Poorly written. By using the word "further" it implies that either uncointrolled separation, loss of generation, or system shutdown has occurred. 8) EOP-003 R6 - Redundant to R5 because after seapration, if frequncy is not restored, there is a risk of further loss of generation and system shutdown. 9)EOP-003 R8 - The second requirement to be capable of implementing load shedding ina timeframe adequate for responding to the emergency can not be met in all circumstances. The problem is with the use of "the emergency". This captures all emergencies, not just the planning scenarios where manual load shedding can be deployed. 10) Consider Adding to the Glossary definitions for Load Shed, and Load Reduction 1) Consider not using the term emergency plan. The proper term is a Plan for Emergencies.
	Individual
	Michael Gammon
	Kansas City Power & Light
	Yes
	Yes
	No
	This should not include Transmission Service Provider, Purchase-Selling Entity. These functions provide for the normal and routine transactions for energy and transmission capacity and do not prohibit or add any reliability related actions taken by Operators.
	Not aware of any regional variances or business practices.
	Do not support the notion of development of specific load shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented. Each region is developing their own regional standard for load shedding and it should be left at that.
	Individual
	James H. Sorrels, Jr.
	American Electric Power
	Yes
	Yes
	Assessing the appropriate applicability of functional entities is part of the scope of the SAR. We believe that this is an appropriate and worthwhile effort.

	None known at this time.
	No additional comments at this time.
	Individual
	Kasia Mihalchuk
	Manitoba Hydro
	Yes
	EOP-001-0 should have the Attachment 1-EOP-001-0 and its 15 elements “assigned” to more appropriate entities. As now they are all directly assigned to TOP and BA. The consistent theme (as per FMPA) is the delegating or clarifying of various requirement responsibilities to the appropriate entities (eg: generation issues to TOP, transmission issues to BA)
	Yes
	From Brief Description: Modify requirements to improve clarity and remove ambiguity; EOP-001 Clarify or justify requirements responsibilities as assigned to TOP and BA. (Example: In PRC-007-0 Introduction describes how each entity is responsible for the Standard or Requirement, TO has to own a UFLS, TOP has to operate UFLS, DP owns or operates UFLS, LSE operate UFLS) The above methodology removes the vagueness of why an entity is assigned an requirement. From Brief Description: Move or eliminate requirements or start new SAR process; EOP-001-0 Attachment 1 and its 15 elements require some work. These elements appear “rough” as they may have been translated from Operating Policies on the Version 0 process. Create a SAR for these items?
	No
	Just examining EOP-001-0 (along with its attachment) involves the following processes: Development Maintain Implement Coordination Load shedding System restoration Fuel and inventory Environmental constraints Customer appeals etc. which are all placed directly on TOP and BA. For instance, Attachment 1, Element 2, Fuel Switching. Does this mean fuel energy for Diesel Backups for black start plants, or the actual supply for a Thermal Unit. Does this include coal? These elements belong directly to a GO.
	Individual
	Greg Rowland
	Duke Energy
	Yes
	Yes
	Only RC responsibilities from IRO-001-1 that relate to emergency plans and operations should be included in the SAR scope. Other RC responsibilities in IRO-001-1 should remain in IRO-001-1.
	Yes
	Business Practice
	Regional Variance: The reliability gap issue with retail power marketers is only applicable to regions with RTOs/ISOs. Business Practice: EOP-002-2 deals with transmission reservations, but does not currently address Conditional Firm Service. We believe that requirements associated with the adjustment of transmission service priorities should be moved to NAESB Business Practices.
	None
	Individual
	Kirit Shah
	Ameren
	Yes
	The current standards are too vague to support reliability and too detailed in other areas where no BES benefit is accrued.
	Yes
	Yes
	Although as the team works through the process it might find additions or deletions need to be made to support reliability. We would offer that the drafting effort recognize this option and not force the standard based on these early assessments.

	We hope that this effort is on a fast-track schedule. Additionally, this may be a group of standards that would be a good fit for treatment as suggested by Gerry Cauley and the “ad-hoc” team
	Individual
	Martin Bauer
	Bureau of Reclamation
	No
	Reclamation does not agree with the SAR as it is written. In order to properly assess the need for this project which proposes to combine three complicated set of requirements into one, the SAR must provide the specifics. The SAR has only general references to inconsistencies with the functional model, phrases such as "various words or elemetns that need clarification"and IRO-001 " applicability issues that must be addressed". The SAR does not be adequately explained why the need the combine the standards. It would be preferable to make revisions to the three standards seperately under one project. Since IRO is being revised, Reclamation believes the SAR should be evaluated after the IRO-001 is revised.
	No
	See previous comment
	Yes
	Individual
	Jason Shaver
	American Transmission Company
	Yes
	Yes
	Yes
	Group
	IRC Standards Review Committee
	Ben Li
	Yes
	Yes
	We generally agree with the scope of the proposed actions. However, we urge the SDT not to presume or pre-determine that the three EOP standards will be merged. EOP-001 deals with operational plans for both resource and transmission emergency, whereas EOP-002 and EOP-003 deal with actions needed in real-time to mitigate generation deficiency. EOP-001 clearly has a place of its own. We do not believe that merging this together with the other two EOP standards will result in any efficiency gain.
	Yes
	Group
	FirstEnergy
	Sam Ciccone

	Yes
	Yes
	Although we agree with the scope, the team should use EOP-001-1 instead of EOP-001-0. EOP-001-1 has been NERC Board approved since October 2008 as part of the "Pre-2006" project on IROLs.
	No
	We are not sure how the Distribution Provider (DP) is involved in the requirements of these standards. They are checked as an applicable entity but no explanation is given as to why they are being added to these standards which currently place no responsibilities on the DP. (Note: UFLS and UVLS schemes can be and are sometimes installed on DP and LSE facilities. This would require applicability to them.)
	FE has the following additional comments: 1. Interpretations which have been approved should be incorporated into these standards to provide clarity. Two examples are the interpretation of EOP-001-0 per Project 2008-09 and the interpretation of EOP-002-2 per project 2008-07. 2. The SAR does not detail modifications directed by FERC Order 693 for standard IRO-001-1. The SAR should add these directives which include: (a) Remove Regional Reliability Organization as an applicable entity (Order 693 pp. 896); (b) Add Measures and Levels of Non-Compliance as requested by APPA (Order 693 pp. 897). Also, although not directives, FERC indicated that NERC should consider FirstEnergy Corp.'s and California Cogeneration's suggestions for improvement. These include: (a) FirstEnergy suggests that NERC clarify whether Requirement R8, which requires entities to comply with a reliability coordinator directive "unless such actions would violate safety, equipment or regulatory or statutory requirements," refers to personnel safety, equipment safety or both. In addition, it suggests the establishment of a chain of command so that, for example, if a generator receives conflicting instructions from a balancing authority and a transmission operator, it can determine which instruction governs (Order 693 pp. 893); (b) California Cogeneration comments that the Reliability Standard fails to address the operational limitations of QFs because they have contractual obligations to provide thermal energy to their industrial hosts. It contends that a QF can be directed to change operations only in the case of a system emergency, pursuant to 18 CFR § 292.307 (Order 693 pp. 895) 3. With regard to EOP-001-1 R2.1, plans to mitigate operating emergencies for insufficient generating capacity are not made in a vacuum. They must consider deliverability of the power and since the BA typically does not have sufficient information about the transmission system to ensure deliverability, the TOP has to assist in this determination. 4. With regard to EOP-001-1 R2.2, plans to mitigate operating emergencies on the transmission system are not made in a vacuum. The Balancing Authority controls the tools used by the Transmission Operator for re-dispatching generation in order to eliminate overloads on the transmission system in instances where the overloaded facility is needed to maintain reliability. Since the TOP typically does not have sufficient information about the generation facilities outside his area of responsibility, the BA has to assist in this determination. 5. With regard to EOP-001-0 R2 load shedding aspects, when load is shed due to insufficient voltage, the TOP is the one who has the tools to recognize the need for this load shed. However, shedding load for an under voltage condition via UFLS impacts the BA. Since this is an automatic operation, the BA needs to know where these facilities are located and how much load can be affected so they know how to react when this load shedding occurs. 6. With regard to EOP-001-1 R4, the current requirement does specify "applicable elements in Attachment 1-EOP-001-0" which removes the items specified in the SAR as problematic and not applicable to the TOP from the list. The solution appears to be two separate lists, one for TOPs and one for BAs. 7. With regard to Requirement R2 of EOP-003-1, the SAR table cites EOP-001-0 rather than EOP-003-1. 8. With regard to the Real-time Best Practices Standards Study Group comment to "Establish document plans and procedures for conservative operations" it is not clear from the SAR what is expected of the drafting team for addressing this comment. Is this something that is missing from the standard? More information is needed with regard to this comment. 9. With regard to FERC's December 20, 2007 and April 4, 2008 Orders, more information is needed with regard to what is expected of the drafting team for addressing these items. It would be more useful to the drafting team if only the excerpts from the order that they are expected to address are included in the SAR. 10. With regard to the Real-time Best Practices Standards Study Group comment to "Provide the location, Real-time status, and MWs of Load available to be shed," it is not clear from the SAR what is expected of the drafting team for addressing this comment. Is this something that is missing from the standard? More information is needed with regard to this comment. 11. The SAR suggests separating the requirements relating to the TOP and BA; one for the BA and one for the TOP. However, this is not reflected in the Standard review forms. Also, this seems contrary to the industry comments contained in the review forms. The SAR should be reconciled to provide a consistent and clear message to the drafting team of what is offered for consideration and what must be included in the new standard. 12. The Standard Review Form for EOP-002-2 makes reference to R10. Version EOP-002-2.1 included in the current version of the reliability standards does not contain an R10. The reference to this requirement should be revised to be correct or removed from the SAR. 13. The Standard Review Form for EOP-003-1 contains a version 0 comment that states "Move to Policy 5 & 9." The reference to these policies should be revised to reflect the applicable standard or removed from the SAR.
	Individual
	Dave Allen
	Operations
	Yes
	The TO's will have plans to mitigate transmission related emergencies and the BA/GO's will follow Directives to support reliability, and the TO will support capacity emergencies without compromizing transmission reliability or safety. The BA's will have plans to mitigate capacity emergencies and will receive support from TO's short of compromizing system reliability or safety. Your reference should point to R2.2 not R3.2

	Yes
	Yes
	Not enough information to support making a decision on this point
	Group
	Southern Company Transmission
	JT Wood
	Yes
	Combining these three standards would improve documentation of applicable requirements. It would also be consistent with the work done with the System Restoration from Blackstart Resources standards. (I would not say these proposed changes are critical to improve reliability but they do present some advantages).
	Yes
	Yes
	Under Applicable Reliability Principles on SAR-5 I believe the following principle should be included: The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand. The goal of the actions taken during Capacity and Energy Emergencies is to return (or at attempt to return) the balance between supply and demand and eventually bring the system back to operate within its reliable operating frequency and voltage limits.
	Group
	Electric Market Policy
	Jalal Babik
	Yes
	Yes
	No
	Nothing in the SAR itself seems to justify addition of the following entities; Transmission Service Provider, Purchasing-Selling Entity, or Load-Serving Entity. Given that, in most cases, these entities do not own physical assets (and if they do, they are probably also registered as either TO, GO or DP), do not see where including them promotes reliability. We did note that they were added in efforts related to Project 2006-06 as well as Project 2007-02. Do not agree with inclusion in Project 2007-02 and noted that many commenters also disagree with inclusion in Project 2006-06.
	None
	None
	Individual
	Derek Bleyle
	SCE&G
	Yes
	Yes
	Yes
	None known.

SCE&G looks at consolidation of redundant requirements and standards as having a positive impact on reliability. We support this objective and feel it is necessary to improve clarity of both requirements and standards.
Individual
Dan Rochester
Independent Electricity System Operator
Yes
Yes
We generally agree with the scope of the proposed actions. However, we urge the SDT not to presume or pre-determine that the three EOP standards will be merged. EOP-001 deals with operational plans for both resource and transmission emergency, whereas EOP-002 and EOP-003 deal with actions needed in real-time to mitigate generation deficiency. EOP-001 clearly has a place of its own. We do not believe that merging this together with the other two EOP standards will result in any efficiency gain.
Yes
We believe the checked entities will largely cover the responsible entities that will be assigned at least a requirement. However, we do not think that the list needs to be exhaustive. The SDT should have the leverage to add entities as needed as it begins drafting the standards.
The Performance-based Reliability Standard Task Force has presented an assessment of the existing standards, a method to develop standards that support reliability performance and risk management, and is working on an overall plan to transition existing standards to a new set of standards. We view the proposed scope of this SAR is largely in line with the Performance-based Reliability Standard Task Force's general direction, and may well be an element of the TF's transition plan. To avoid duplicated work and to support prioritization of needed projects balancing scarce resource, we suggest the SAR proponent to liaison with Dave Taylor of NERC to identify the best way forward including whether or not this project should proceed alone and if so, the timing to start drafting the standards.
Group
Midwest ISO Standards Collaborators
Jason L. Marshall
Yes
Yes
Yes
Individual
Scott Barfield
Georgia System Operations Corporation
No
It is assumed that the word "either" in question 1 was not intended since there was only one statement to agree or disagree with. There is not a reliability-related need for modifications to these standards. There is a need for clarity. Lack of clarity could possibly affect reliability if it leads to misunderstandings that may lead to wrong actions by entities. There is also a need for measurability and reasonableness of the requirements. There is a need to eliminate requirements that do not impact the BES and eliminate redundant requirements. These needs are compliance-monitoring/enforcement-related needs and not reliability-related needs. Combining these 3 standards is not necessary but would be an improvement and is supported. It is agreed that the 3 bullets of options, under the "Brief Description" section for proposed changes, are desired goals.
No
The scope may be good but it may also help improve the standards and compliance monitoring or enforcement if EOP-005 would be merged together with these 3 standards included in the SAR. EOP-005 is interrelated with the 3 standards. If merging EOP-005 with the other 3 would make the resulting merged standard too long, then EOP-005 could still stand alone.
At least one requirement in the 3 existing standards applies to each of the entities listed except to a DP. As long as an existing requirement is not extended to entities not now included. If EOP-005 is merged in, it is agreed that a DP should be covered because they are involved in system restoration. It is possible that they also should be covered

	because they may be involved in load shedding.
	No known variances
	Declaring/communicating when an entity is in an alert level should remain in the appropriate EOP/IRO standards and not moved to a COM standard. The requirements relating to emergencies in all other groups of standards (mainly BAL, COM, IRO, and TOP) should be moved to EOP standards. The BAL, IRO, and TOP standards should cover non-emergency requirements. An exception should be requirements relating to training, drills, and tests which should be moved to the PER standards and removed from EOP and other standards. Some requirements for load shedding (e.g., automatic load shed) should be moved to PRC standards and not included in the EOP standards.
	Group
	NERC Standards Review Subcommittee
	Carol Gerou
	Yes
	Yes
	Yes
	N/A
	N/A

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RELIABILITY CORPORATION

Consideration of Comments on Emergency Operations SAR — Project 2009-03

The Emergency Operations SAR Drafting Team thanks all commenters who submitted comments on the SAR. The SAR was posted for a 45-day public comment period from December 7, 2009 through January 15, 2010. Stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 20 sets of comments, including comments from more than 70 different people from over 35 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

For this report, the comments have been organized by question number so it is easier to see where there is consensus. The comments submitted can be reviewed in their original format on the following Web page:

http://www.nerc.com/filez/standards/Project2009-03_Emergency_Operations.html

Most commenters agreed that there is a reliability-related need for the proposed standard actions and agreed that the clarity of the standards needs improvement. Commenters also suggested that the DT include the NERC BOT approved versions of the standards, the DT agreed and modified the SAR. The majority of commenters agreed that the list of functional entities was accurate but some commenters questioned the inclusion of the DPs, TSPs, PSEs, and LSEs. The DT responded that "The identification of a functional entity in the SAR does not mean that it will be included as an applicable entity in the revised standards. Its inclusion (in the scope) of the SAR allows the SDT to investigate their potential role, if any, in the revised standards." Numerous commenters made suggestions that pertained to the standards rather than the SAR and the DT will address those during the standard drafting phase of the project. Minor changes were made to the SAR in response to stakeholder comments.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standards Processes Manual: http://www.nerc.com/filez/standards/Standards_Processes_Manual.html

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Brian D. Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	David Kiguel	Hydro One Networks Inc.	NPCC	1
12.	Michael R. Lombardi	Northeast Utilities	NPCC	1
13.	Randy MacDonald	New Brunswick System Operator	NPCC	2
14.	Greg Mason	Dynegy Generation	NPCC	5

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

15. Bruce Metruck	New York Power Authority	NPCC	6
16. Chris Orzel	FPL Energy/NextEra Energy	NPCC	5
17. Robert Pellegrini	The United Illuminating Company	NPCC	1
18. Saurabh Saksena	National Grid	NPCC	1
19. Michael Schiavone	National Grid	NPCC	1
20. Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
21. Gerry Dunbar	Northeast Power Coordinating Council	NPCC	NA
22. Lee Pedowicz	Northeast Power Coordinating Council	NPCC	NA

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Jim Burns	Transmission Technical Operations	WECC	1
2. Sally Long	Transmission Technical Operations	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	Ben Li	IRC Standards Review Committee		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Bill Phillips	MISO	MRO	2
2. Al Dicaprio	PJM	RFC	2
3. Mark Thompson	AESO	WECC	2
4. Charles Yeung	SPP	SPP	2
5. Steve Myers	ERCOT	ERCOT	2
6. Matt Goldberg	ISO-NE	NPCC	2
7. Lourdes Estrada-Salinero	CAISO	WECC	2
8. Jim Castle	NYISO	NPCC	2

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Sam Ciccone	FirstEnergy	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Dave Folk	FirstEnergy	RFC	1, 3, 4, 5, 6
2. Doug Hohlbaugh	FirstEnergy	RFC	1, 3, 4, 5, 6
3. Steve Megay	FirstEnergy	RFC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
4.	John Reed	FirstEnergy	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5.	Group	Jalal Babik	Electric Market Policy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade		RFC	5
2.	Mike Garton		NPCC	6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Jason L. Marshall	Midwest ISO Standards Collaborators		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Barb Kedrowski	We Energies	RFC	3, 4, 5
2.	Kirit Shah	Ameren	SERC	1
3.	Jim Cyrulewski	JDRJC Associates, LLC	RFC	8
4.	Joe Knight	Great River Energy	MRO	1, 3, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Carol Gerou	NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Chuck Lawrence	American Transmission Company	MRO	1
2.	Tom Webb	WPS Corporation	MRO	3, 4, 5, 6
3.	Terry Bilke	Midwest ISO Inc	MRO	2
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
10.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
11.	Scott Nickels	Rochester Public Utilties	MRO	4
12.	Terry Harbour	MidAmerican Energy Company	MRO	6, 1, 3, 5

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Individual	JT Wood	Southern Company Transmission	X		X							

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
9.	Individual	Jonathan Appelbaum	Long Island Power Authority	X									
10.	Individual	Michael Gammon	Kansas City Power & Light	X		X		X	X				
11.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X					
12.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
13.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
14.	Individual	Kirit Shah	Ameren	X		X		X	X				
15.	Individual	Martin Bauer	Bureau of Reclamation					X					
16.	Individual	Jason Shaver	American Transmission Company	X									
17.	Individual	Dave Allen	Operations	X									
18.	Individual	Derek Bleyle	SCE&G	X		X		X	X				
19.	Individual	Dan Rochester	Independent Electricity System Operator		X								
20.	Individual	Scott Barfield	Georgia System Operations Corporation			X	X						

1. Do you agree that either there is a reliability-related need for the proposed standards action?

Summary Consideration: Most commenters agreed that there is a reliability-related need for the proposed standard actions. Several commenters made suggestions that pertained to the standards rather than the SAR and the DT will address those during the standard drafting phase of the project.

Organization	Yes or No	Question 1 Comment
Georgia System Operations Corporation	No	It is assumed that the word "either" in question 1 was not intended since there was only one statement to agree or disagree with. There is not a reliability-related need for modifications to these standards. There is a need for clarity. Lack of clarity could possibly affect reliability if it leads to misunderstandings that may lead to wrong actions by entities. There is also a need for measurability and reasonableness of the requirements. There is a need to eliminate requirements that do not impact the BES and eliminate redundant requirements. These needs are compliance-monitoring/enforcement-related needs and not reliability-related needs. Combining these 3 standards is not necessary but would be an improvement and is supported. It is agreed that the 3 bullets of options, under the "Brief Description" section for proposed changes, are desired goals.
Response: The Drafting Team (DT) agrees with your comment. The question should read "Do you agree that there is a reliability-related need for the proposed standard action?"		
Bureau of Reclamation	No	Reclamation does not agree with the SAR as it is written. In order to properly assess the need for this project which proposes to combine three complicated set of requirements into one, the SAR must provide the specifics. The SAR has only general references to inconsistencies with the functional model, phrases such as "various words or elements that need clarification "and IRO-001 "applicability issues that must be addressed". The SAR does not adequately explain the need to combine the standards. It would be preferable to make revisions to the three standards separately under one project. Since IRO is being revised, Reclamation believes the SAR should be evaluated after the IRO-001 is revised.
Response: The DT appreciates your comment. IRO-001-1 was originally a part of this project but has been removed because all of the issues and directives associated with that standard have been addressed by the Reliability Coordination SDT, Project 2006-06. The DT will evaluate the practicality or need to combine the three EOP standards.		
American Electric Power	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 1 Comment
Bonneville Power Administration	Yes	
Duke Energy	Yes	
Electric Market Policy	Yes	
FirstEnergy	Yes	
Independent Electricity System Operator	Yes	
IRC Standards Review Committee	Yes	
Kansas City Power & Light	Yes	
Long Island Power Authority	Yes	
Midwest ISO Standards Collaborators	Yes	
NERC Standards Review Subcommittee	Yes	
Northeast Power Coordinating Council	Yes	
SCE&G	Yes	
Southern Company Transmission	Yes	Combining these three standards would improve documentation of applicable requirements. It would also be consistent with the work done with the System Restoration from Blackstart Resources standards. (I would not say these proposed changes are critical to improve reliability but they do present some advantages).
Response: The DT appreciates your support and comments.		

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Yes	EOP-001-0 should have the Attachment 1-EOP-001-0 and its 15 elements “assigned” to more appropriate entities. As now they are all directly assigned to TOP and BA. The consistent theme (as per FMPA) is the delegating or clarifying of various requirement responsibilities to the appropriate entities (e.g.: generation issues to TOP, transmission issues to BA)
Response: The DT appreciates your support and comments. The list of issues that will be addressed by the Standard Drafting Team does include clarification of the responsible entity.		
Ameren	Yes	The current standards are too vague to support reliability and too detailed in other areas where no BES benefit is accrued.
Response: The DT appreciates your support and comment.		
Operations	Yes	The TO's will have plans to mitigate transmission related emergencies and the BA/GO's will follow Directives to support reliability, and the TO will support capacity emergencies without compromising transmission reliability or safety. The BA's will have plans to mitigate capacity emergencies and will receive support from TO's short of compromising system reliability or safety. Your reference should point to R2.2 not R3.2
Response: The DT appreciates your support and comments. When this SAR was originally drafted, the version of EOP-001 that was in effect was EOP-001-0, and it was R3.2 that included the requirement for both Transmission Operators and Balancing Authorities to develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system. When EOP-001-0 was updated and replaced with EOP-001-1, this subrequirement was renumbered as R2.2.		

2. Do you agree with the scope of the proposed standards action?

Summary Consideration: The majority of commenters believed that merging the three EOP standards should be considered; a few commenters suggested that the DT not have a predetermined mindset. One commenter suggested that the DT include the NERC BOT approved version of the standards. The DT agreed with this suggestion and has modified the SAR. Several commenters made suggestions that pertained to the standards rather than the SAR and the DT will address those during the standard drafting phase of the project.

Organization	Yes or No	Question 2 Comment
Bureau of Reclamation	No	See previous comment
Response: The DT appreciates your comment. IRO-001-1 was originally a part of this project but has been removed because all of the issues and directives associated with that standard have been addressed by the Reliability Coordination SDT, Project 2006-06. The DT will evaluate the practicality or need to combine the three EOP standards.		
Georgia System Operations Corporation	No	The scope may be good but it may also help improve the standards and compliance monitoring or enforcement if EOP-005 would be merged together with these 3 standards included in the SAR. EOP-005 is interrelated with the 3 standards. If merging EOP-005 with the other 3 would make the resulting merged standard too long, then EOP-005 could still stand alone.
Response: The DT thanks you for your comments. As EOP-005-2 was just recently completed, making additional changes before the standard has had a chance to be fully implemented would not be an efficient use of industry resources.		
Ameren	Yes	
American Electric Power	Yes	
American Transmission Company	Yes	
Electric Market Policy	Yes	
Kansas City Power & Light	Yes	

Organization	Yes or No	Question 2 Comment
Long Island Power Authority	Yes	
Midwest ISO Standards Collaborators	Yes	
NERC Standards Review Subcommittee	Yes	
Operations	Yes	
SCE&G	Yes	
Southern Company Transmission	Yes	
Bonneville Power Administration	Yes	a. Agree with the idea of merging EOP-001-0, EOP-002-2, and EOP-003-1 into a single Standard. b. Requirement 8 from IRO-001-1 should be included in a new single EOP standard and removed from IRO-001-1. This would allow IRO-001-1 to apply only to Reliability Coordinators and Regional Reliability Organizations. .c. BPA supports improving clarity and removing redundant and non essential requirements (those that don't support bulk power system reliability.
Response: The DT appreciates your support and comments. These issues will be addressed by the Standard Drafting Team. IRO-001-1 was originally a part of this project but has been removed because all of the issues and directives associated with that standard have been addressed by the Reliability Coordination SDT, Project 2006-06.		
FirstEnergy	Yes	Although we agree with the scope, the team should use EOP-001-1 instead of EOP-001-0. EOP-001-1 has been NERC Board approved since October 2008 as part of the "Pre-2006" project on IROLs.
Response: The DT appreciates your support and comments. The DT agrees with your comment and will include EOP-001-1 and EOP-001-2 in the revised SAR.		
Manitoba Hydro	Yes	From Brief Description: Modify requirements to improve clarity and remove ambiguity; EOP-001. Clarify or justify requirements, responsibilities as assigned to TOP and BA. (Example: In PRC-007-0 Introduction describes how each entity is responsible for the Standard or Requirement, TO has to own a UFLS, TOP has to operate UFLS, DP owns or operates UFLS, LSE operate UFLS)The above methodology removes the vagueness of why an entity is assigned a requirement. From Brief Description: Move or eliminate

Organization	Yes or No	Question 2 Comment
		requirements or start new SAR process; EOP-001-0 Attachment 1 and its15 elements require some work. These elements appear "rough" as they may have been translated from Operating Policies on the Version 0 process. Create a SAR for these items?
Response: The DT appreciates your support and comments. The list of issues that will be addressed by the Standard Drafting Team does include clarification of the responsible entity. A single SAR can be used to modify several standards, so there is no need to develop a separate SAR for EOP-001 Attachment 1.		
Duke Energy	Yes	Only RC responsibilities from IRO-001-1 that relate to emergency plans and operations should be included in the SAR scope. Other RC responsibilities in IRO-001-1 should remain in IRO-001-1.
Response: The DT appreciates your support and comments. IRO-001 was originally a part of this project but has been removed because all of the issues and directives associated with that standard have been addressed by the Reliability Coordination SDT, Project 2006-06.		
Northeast Power Coordinating Council	Yes	The SDT should not assume that the three EOP standards will be merged. EOP-001 deals with operational plans for both resource and transmission emergencies, whereas EOP-002 and EOP-003 deal with the actions needed in real-time to mitigate generation deficiency. EOP-001 is unique when compared with EOP-002, and EOP-003. Merging EOP-001 with the other two EOP standards will not result in gain in efficiency. The SDT should not assume that the three EOP standards will be merged. EOP-001 deals with operational plans for both resource and transmission emergencies, whereas EOP-002 and EOP-003 deal with the actions needed in real-time to mitigate generation deficiency. EOP-001 is unique when compared with EOP-002, and EOP-003. Merging EOP-001 with the other two EOP standards will not result in a gain in efficiency.
Response: The DT appreciates your comment. The DT will evaluate the practicality or need to combine the three EOP standards.		
Independent Electricity System Operator	Yes	We generally agree with the scope of the proposed actions. However, we urge the SDT not to presume or pre-determine that the three EOP standards will be merged. EOP-001 deals with operational plans for both resource and transmission emergency, whereas EOP-002 and EOP-003 deal with actions needed in real-time to mitigate generation deficiency. EOP-001 clearly has a place of its own. We do not believe that merging this together with the other two EOP standards will result in any efficiency gain.
IRC Standards Review Committee	Yes	We generally agree with the scope of the proposed actions. However, we urge the SDT not to presume or pre-determine that the three EOP standards will be merged. EOP-001 deals with operational plans for both resource and transmission emergency, whereas EOP-002 and EOP-003 deal with actions needed in real-time to mitigate generation deficiency. EOP-001 clearly has a place of its own. We do not believe that merging this together with the other two EOP standards will result in any efficiency gain.

Organization	Yes or No	Question 2 Comment
Response: The DT appreciates your support and comments. The list of issues that will be addressed by the Standard Drafting Team does include clarification of the responsible entity.		

3. Do you agree that the list of entities includes all those functional entities that may have one or more requirements assigned to them as part of this project? If not, please state specific reasons why not.

Summary Consideration: The majority of commenters agreed that the list of functional entities was accurate but some commenters questioned the inclusion of the DPs, TSPs, PSEs, and LSEs. The DT will consider the applicability of all functional entities throughout the Standard development phase.

Organization	Yes or No	Question 3 Comment
American Electric Power		Assessing the appropriate applicability of functional entities is part of the scope of the SAR. We believe that this is an appropriate and worthwhile effort.
Response: The DT appreciates your comments.		
Georgia System Operations Corporation		At least one requirement in the 3 existing standards applies to each of the entities listed except to a DP. As long as an existing requirement is not extended to entities not now included. If EOP-005 is merged in, it is agreed that a DP should be covered because they are involved in system restoration. It is possible that they also should be covered because they may be involved in load shedding.
Response: The DT appreciates your comments. The identification of a functional entity in the SAR does not mean that it will be included as an applicable entity in the revised standards. Its inclusion (in the scope) of the SAR allows the SDT to investigate their potential role, if any, in the revised standards. The Distribution Provider (DP) has been identified as a functional entity that 'may' have responsibility for some requirements in the revised standards. The Reliability Functional Model, Version 5, states that the DP (Real Time): Implements voltage reduction and sheds load as directed by the Transmission Operator or Balancing Authority.		
Manitoba Hydro	No	Just examining EOP-001-0 (along with its attachment) involves the following processes: Development Maintain Implement Coordination Load shedding System Restoration Fuel and Inventory Environmental constraints Customer appeals, etc. which are all placed directly on TOP and BA. For instance, Attachment 1, Element 2, Fuel Switching. Does this mean fuel energy for Diesel Backups for black start plants, or the actual supply for a Thermal Unit? Does this include coal? These elements belong directly to a GO.
Response: The DT appreciates your comments. The identification of a functional entity in the SAR does not mean that it will be included as an applicable entity in the revised standards. Its inclusion (in the scope) of the SAR allows the SDT to investigate their potential role, if any, in the revised standards. The Generator Owner has been identified as a functional entity that 'may' have responsibility for some requirements in the revised standards because of the fuel elements listed in Attachment 1.		
Electric Market Policy	No	Nothing in the SAR itself seems to justify addition of the following entities; Transmission Service Provider,

Organization	Yes or No	Question 3 Comment
		Purchasing-Selling Entity, or Load-Serving Entity. Given that, in most cases, these entities do not own physical assets (and if they do, they are probably also registered as either TO, GO or DP), do not see where including them promotes reliability. We did note that they were added in efforts related to Project 2006-06 as well as Project 2007-02. Do not agree with inclusion in Project 2007-02 and noted that many commenters also disagree with inclusion in Project 2006-06.
Response: The DT appreciates your comments. The identification of a functional entity in the SAR does not mean that it will be included as an applicable entity in the revised standards. Its inclusion (in the scope) of the SAR allows the SDT to investigate their potential role, if any, in the revised standards.		
Kansas City Power & Light	No	This should not include Transmission Service Provider, Purchase-Selling Entity. These functions provide for the normal and routine transactions for energy and transmission capacity and do not prohibit or add any reliability related actions taken by Operators.
Response: The DT appreciates your comments. The identification of a functional entity in the SAR does not mean that it will be included as an applicable entity in the revised standards. Its inclusion (in the scope) of the SAR allows the SDT to investigate their potential role, if any, in the revised standards.		
FirstEnergy	No	We are not sure how the Distribution Provider (DP) is involved in the requirements of these standards. They are checked as an applicable entity but no explanation is given as to why they are being added to these standards which currently place no responsibilities on the DP. (Note: UFLS and UVLS schemes can be and are sometimes installed on DP and LSE facilities. This would require applicability to them.)
Response: The DT appreciates your comments. The Distribution Provider (DP) has been identified as a functional entity that 'may' have responsibility for some requirements in the revised standards. The Reliability Functional Model, Version 5, states that the DP (Real Time): Implements voltage reduction and sheds load as directed by the Transmission Operator or Balancing Authority. The inclusion of the LSE in the SAR does not mean that they will be included as an applicable entity in the revised standards. Their inclusion (in the scope) of the SAR allows the SDT to investigate their potential role, if any, in the revised standards.		
American Transmission Company	Yes	
Bonneville Power Administration	Yes	
Bureau of Reclamation	Yes	

Organization	Yes or No	Question 3 Comment
Duke Energy	Yes	
IRC Standards Review Committee	Yes	
Long Island Power Authority	Yes	
Midwest ISO Standards Collaborators	Yes	
NERC Standards Review Subcommittee	Yes	
Northeast Power Coordinating Council	Yes	
Operations	Yes	
SCE&G	Yes	
Southern Company Transmission	Yes	
Ameren	Yes	Although as the team works through the process it might find additions or deletions need to be made to support reliability. We would offer that the drafting effort recognize this option and not force the standard based on these early assessments.
Response: The DT appreciates your support and comments.		
Independent Electricity System Operator	Yes	We believe the checked entities will largely cover the responsible entities that will be assigned at least a requirement. However, we do not think that the list needs to be exhaustive. The SDT should have the leverage to add entities as needed as it begins drafting the standards.
Response: The DT appreciates your support and comments.		

4. If you are aware of the need for a regional variance or business practice that we should consider with this SAR, please identify it here.

Summary Consideration: Most commenters did not mention any known regional variances or business practices that should be considered. However, a concern was raised on recent NAESB changes to transmission service types that may need to be addressed; either in this set of standards or by NAESB.

Organization	Yes or No	Question 4 Comment
NERC Standards Review Subcommittee		N/A
Georgia System Operations Corporation		No known variances
Electric Market Policy		None
American Electric Power		None known at this time.
SCE&G		None known.
Kansas City Power & Light		Not aware of any regional variances or business practices.
Operations		Not enough information to support making a decision on this point
Response: The DT appreciates your comment.		
Duke Energy	Business Practice	Regional Variance: The reliability gap issue with retail power marketers is only applicable to regions with RTOs/ISOs. Business Practice: EOP-002-2 deals with transmission reservations, but does not currently address Conditional Firm Service. We believe that requirements associated with the adjustment of transmission service priorities should be moved to NAESB Business Practices.
Response: The DT appreciates your comment and will address these issues during the standards drafting phase.		

5. **If you have any other comments on this SAR that you have not already provided in response to the prior questions, please provide them here. Note that any comments recommending specific changes to the standards will be forwarded to the standard drafting team and will not be addressed by the SAR drafting team.**

Summary Consideration: Most commenters agreed that there is a reliability-related need for the proposed standard actions. Numerous commenters mentioned the clarity of the standards needed improvement. The DT reiterated that writing clear unambiguous requirements is NERC's goal. Numerous commenters made suggestions that pertained to the standards rather than the SAR and the DT will address those during the standard drafting phase of the project. The DT made minor changes to the wording of the SAR in response to a commenter.

- The first sentence on Page SAR-2, under Industry Need was changed to: "The industry needs standards that are technically accurate, clearly written so as to leave no confusion as to what a requirement means, and support the overall goal of ensuring bulk power system reliability."
- In the Global Improvements section on Page SAR-13, the second sentence was modified to read: "Additionally, each standard must be clearly written, so that bulk power system users, owners, and operators are informed of the expected behavior or have knowledge of the expected behavior." The DT has received results-based training and will incorporate these concepts into this project.
- The DT added a list of relevant interpretations to the SAR.

Organization	Question 5 Comment
Bonneville Power Administration	a. In the paragraph under Industry Need, page SAR-2, suggest that the first sentence be rewritten to state as follows: "The industry needs standards that are technically accurate, clearly written so as to leave no confusion as to what a requirement means, and support the overall goal of ensuring bulk power system reliability". b. One concern with the EOP standards - and others - is the lack of use of the defined terms - with appropriate capitalization - from the NERC Glossary of Terms Used in Reliability Standards. The use of these terms without appropriate capitalization leads to confusion as to whether the words in the requirement mean something different than the defined term. c. On page SAR-10 The EOP-002-2 the comment from FERC about not using the TLR procedure to mitigate IROL violations doesn't seem right. IS FERC saying to allow an IROL to be VIOLATED (TOP-004 R1) by not changing phase shifters or ATC corrections or etc, so that a deficient entity won't be forced to shed load under a EEA? EOP-001 R2 says to have load reduction available to mitigate IROL. Or do they mean re-evaluate the IROL limits first which is already in

Organization	Question 5 Comment
	the standard? d. In Attachment 2, page SAR-12, paragraph 3, suggest rewording 2nd sentence to say "Additionally, each standard must be clearly written, so that bulk power system users, owners, and operators are informed of the expected behavior (or have knowledge of the expected behavior, rather than "put on notice").
Response: **a. The DT appreciates your comments and believes the statement as written captures your thought. Writing clear unambiguous requirements is NERC's goal.** **b. Your comments will be considered during the standard drafting phase of the project.** **c. The bullets in the SAR pertaining to the FERC directives from Order No. 693 are summaries, the full version of the directive is included in Order No. 693 Paragraph 574 through Paragraph 577.** **d. The DT agrees with your comment and has modified the SAR.**	
Georgia System Operations Corporation	Declaring/communicating when an entity is in an alert level should remain in the appropriate EOP/IRO standards and not moved to a COM standard. The requirements relating to emergencies in all other groups of standards (mainly BAL, COM, IRO, and TOP) should be moved to EOP standards. The BAL, IRO, and TOP standards should cover non-emergency requirements. An exception should be requirements relating to training, drills, and tests which should be moved to the PER standards and removed from EOP and other standards. Some requirements for load shedding (e.g., automatic load shed) should be moved to PRC standards and not included in the EOP standards.
Response: The DT appreciates your comments. Your comments will be considered during the standard drafting phase of the project.	
Kansas City Power & Light	Do not support the notion of development of specific load shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented. Each region is developing their own regional standard for load shedding and it should be left at that.
Response: The DT appreciates your comments. Your comments will be considered during the standard drafting phase of the project.	
FirstEnergy	FE has the following additional comments: 1. Interpretations which have been approved should be incorporated into these standards to provide clarity. Two examples are the interpretation of EOP-001-0 per Project 2008-09 and the interpretation of EOP-002-2 per project 2008-07. 2. The SAR does not detail modifications directed by FERC Order 693 for standard IRO-001-1. The SAR should add

Organization	Question 5 Comment
	these directives which include: (a) Remove Regional Reliability Organization as an applicable entity (Order 693 pp. 896); (b) Add Measures and Levels of Non-Compliance as requested by APPA (Order 693 pp. 897). Also, although not directives, FERC indicated that NERC should consider FirstEnergy Corp.'s and California Cogeneration's suggestions for improvement. These include: (a) FirstEnergy suggests that NERC clarify whether Requirement R8, which requires entities to comply with a reliability coordinator directive "unless such actions would violate safety, equipment or regulatory or statutory requirements," refers to personnel safety, equipment safety or both. In addition, it suggests the establishment of a chain of command so that, for example, if a generator receives conflicting instructions from a balancing authority and a transmission operator, it can determine which instruction governs (Order 693 pp. 893); (b) California Cogeneration comments that the Reliability Standard fails to address the operational limitations of QFs because they have contractual obligations to provide thermal energy to their industrial hosts. It contends that a QF can be directed to change operations only in the case of a system emergency, pursuant to 18 CFR Â§ 292.307 (Order 693 pp. 895) 3. With regard to EOP-001-1 R2.1, plans to mitigate operating emergencies for insufficient generating capacity are not made in a vacuum. They must consider deliverability of the power and since the BA typically does not have sufficient information about the transmission system to ensure deliverability, the TOP has to assist in this determination. 4. With regard to EOP-001-1 R2.2, plans to mitigate operating emergencies on the transmission system are not made in a vacuum. The Balancing Authority controls the tools used by the Transmission Operator for re-dispatching generation in order to eliminate overloads on the transmission system in instances where the overloaded facility is needed to maintain reliability. Since the TOP typically does not have sufficient information about the generation facilities outside his area of responsibility, the BA has to assist in this determination. 5. With regard to EOP-001-0 R2 load shedding aspects, when load is shed due to insufficient voltage, the TOP is the one who has the tools to recognize the need for this load shed. However, shedding load for an under voltage condition via UFLS impacts the BA. Since this is an automatic operation, the BA needs to know where these facilities are located and how much load can be affected so they know how to react when this load shedding occurs. 6. With regard to EOP-001-1 R4, the current requirement does specify "applicable elements in Attachment 1-EOP-001-0" which removes the items specified in the SAR as problematic and not applicable to the TOP from the list. The solution appears to be two separate lists, one for TOPs and one for BAs. 7. With regard to Requirement R2 of EOP-003-1, the SAR table cites EOP-001-0 rather than EOP-003-1. 8. With regard to the Real-time Best Practices Standards Study Group comment to "Establish document plans and procedures for conservative operations" it is not clear from the SAR what is expected of the drafting team for addressing this comment. Is this something that is missing from the standard? More information is needed with regard to this comment. 9. With regard to FERC's December 20, 2007 and April 4, 2008 Orders, more information is needed with regard to what

Organization	Question 5 Comment
	is expected of the drafting team for addressing these items. It would be more useful to the drafting team if only the excerpts from the order that they are expected to address are included in the SAR. 10. With regard to the Real-time Best Practices Standards Study Group comment to "Provide the location, Real-time status, and MWs of Load available to be shed," it is not clear from the SAR what is expected of the drafting team for addressing this comment. Is this something that is missing from the standard? More information is needed with regard to this comment. 11. The SAR suggests separating the requirements relating to the TOP and BA; one for the BA and one for the TOP. However, this is not reflected in the Standard review forms. Also, this seems contrary to the industry comments contained in the review forms. The SAR should be reconciled to provide a consistent and clear message to the drafting team of what is offered for consideration and what must be included in the new standard. 12. The Standard Review Form for EOP-002-2 makes reference to R10. Version EOP-002-2.1 included in the current version of the reliability standards does not contain an R10. The reference to this requirement should be revised to be correct or removed from the SAR. 13. The Standard Review Form for EOP-003-1 contains a version 0 comment that states "Move to Policy 5 & 9." The reference to these policies should be revised to reflect the applicable standard or removed from the SAR.

Response: The DT appreciates your comments.

1. **The team has added a list of relevant interpretations to the SAR in support of your comment.**
2. **IRO-001-1 was originally a part of this project but has been removed because all of the issues and directives associated with that standard have been addressed by the Reliability Coordination SDT, Project 2006-06.**
3. **The DT will consider your comments and suggestions during the standard drafting phase of the project.**
4. **The DT will consider your comments and suggestions during the standard drafting phase of the project.**
5. **The DT will consider your comments and suggestions during the standard drafting phase of the project.**
6. **The DT will consider your comments and suggestions during the standard drafting phase of the project.**
7. **The DT thanks you for catching this mistake. The relevant standard is EOP-003-1 and will be corrected in the modified SAR.**
8. **The Standard Drafting Team will consider all issues listed in the SAR; as such, the SDT will discuss the idea of 'conservative operations'.**
9. **The DT agrees with your comment. The SDT will resolve the issue and post the resolution.**
10. **The Standard Drafting Team will consider all issues listed in the SAR; as such, the SDT will discuss the inclusion of this type of information in the revised standards.**

Organization	Question 5 Comment
11. As stated in the 'Brief Description' on page 3 of the SAR: "The standard drafting team will review the associated items in what is termed the "NERC Standards Issues Database (Issues Database)." The Issues Database is used by the NERC standards program staff to track the issues and concerns identified with a particular standard. Prior to the development of the Issues Database, the Standard Review Form was utilized to capture all issues referencing a particular standard. The Standard Review Forms and the Issues Database excerpts applicable to these standards are listed in (Attachment 1). **12. The DT agrees and thanks for your comment and suggestion. The VRF comments referencing Requirement R10 should reference Requirement R9.** **13. The DT agrees and will make the appropriate response to those comments. Some older comments have lost relevancy due to standard revisions.**	
NERC Standards Review Subcommittee	N/A
American Electric Power	No additional comments at this time.
Duke Energy	None
Electric Market Policy	None
Response:	
SCE&G	SCE&G looks at consolidation of redundant requirements and standards as having a positive impact on reliability. We support this objective and feel it is necessary to improve clarity of both requirements and standards.
Response: The DT appreciates your support and comment.	
Independent Electricity System Operator	The Performance-based Reliability Standard Task Force has presented an assessment of the existing standards, a method to develop standards that support reliability performance and risk management, and is working on an overall plan to transition existing standards to a new set of standards. We view the proposed scope of this SAR is largely in line with the Performance-based Reliability Standard Task Force's general direction, and may well be an element of the TF's transition plan. To avoid duplicated work and to support prioritization of needed projects balancing scarce resource, we suggest the SAR proponent to liaison with Dave Taylor of NERC to identify the best way forward including whether or not this project should proceed alone and if so, the timing to start drafting the standards.

Organization	Question 5 Comment
Response: The DT appreciates your support and comment, and has collaborated with the group responsible for implementing results-based standards. The DT was trained on and will be implementing the result-based concepts in this project.	
Long Island Power Authority	These comments are for the SDT. Reference is to existing standards: 1) EOP-001 R2.3 requires plans for load shedding and so does EOP-003 2) EOP-001 R2 and R3 can be merged. 3) EOP-001 R6 - Uses the term "coordinate with other...as appropriate". How is "appropriate" determined? Suggest tie it in with existing R3.3. 4) EOP-001 R6.3 - Consider eliminating because its literal meaning means in an emergency do one or the other, not both, and nothing else. 5) EOP-001 R6.4 - Transmission Operators do not arrange for fuel deliveries to Generators. What does arranging for electrical energy through normal operating channels mean? If it's an emergency, can there be an Emergency communication protocol? 6) EOP-003 R2 and R3 - Eliminate. The under frequency load shed program is developed by the Regional Entity in PRC-006. 7) EOP-003 R5 - Poorly written. By using the word "further" it implies that either uncontrolled separation, loss of generation, or system shutdown has occurred. 8) EOP-003 R6 - Redundant to R5 because after separation, if frequency is not restored, there is a risk of further loss of generation and system shutdown. 9) EOP-003 R8 - The second requirement to be capable of implementing load shedding in a timeframe adequate for responding to the emergency can not be met in all circumstances. The problem is with the use of "the emergency". This captures all emergencies, not just the planning scenarios where manual load shedding can be deployed. 1 0) Consider Adding to the Glossary definitions for Load Shed, and Load Reduction1) Consider not using the term emergency plan. The proper term is a Plan for Emergencies.
Response: The DT appreciates your comments. Your comments will be considered during the standard drafting phase of the project.	
Southern Company Transmission	Under Applicable Reliability Principles on SAR-5 I believe the following principle should be included: The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand. The goal of the actions taken during Capacity and Energy Emergencies is to return (or at attempt to return) the balance between supply and demand and eventually bring the system back to operate within

Organization	Question 5 Comment
	its reliable operating frequency and voltage limits.
Response: The DT agrees and appreciates your comments. The SAR will be modified appropriately to include this Reliability Principle.	
Ameren	We hope that this effort is on a fast-track schedule. Additionally, this may be a group of standards that would be a good fit for treatment as suggested by Gerry Cauley and the “ad-hoc” team
Response: The DT appreciates your support and comments. It is the Standards Committee’s responsibility to direct the DTs and the DT will comply with that direction. The standards developed under this project will be developed using the results-based Process suggested by Gerry Cauley.	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Nomination Form for Project 2009-03 Emergency Operations SAR Drafting Team

Please use the electronic nomination form located at the link below to submit your nomination by **December 18, 2009** to participate on the SAR Drafting Team. If you have any questions, please contact David Taylor at david.taylor@nerc.net.

http://www.nerc.com/filez/standards/Project2009-03_Emergency_Operations.html

By submitting the following information you are indicating your willingness and agreement to actively participate in the Standard Authorization Request (SAR) development process and SAR Drafting Team (SAR DT) meetings if appointed to the SAR Drafting Team by the Standards Committee. This includes a commitment to travel to and attend face-to-face meetings of the SAR DT, participate in conference call meetings of the SAR DT, as well as perform additional work required by the SAR DT outside of drafting team meetings. It is estimated that for a typical SAR development project approximately 100 hours of your time (assuming 8 hours in a work day) will be needed over the approximate eight month duration of the project.

Name:	
Organization:	
Address:	
Telephone:	
E-mail:	

The SAR DT is responsible for working with the requestor of the SAR to finalize the language of the SAR. The SAR defines the scope of the work the standard drafting team will undertake for the subject project. Once the SAR is finalized and approved by the Standards Committee the SAR DT will be disbanded.

The draft SAR for **Project 2009-03 — Emergency Operations** proposes revisions to the following standards:

- EOP-001-0 — Emergency Operations Planning
- EOP-002-2 — Capacity and Energy Emergencies
- EOP-003-1 — Load Shedding Plans
- IRO-001-1 — Reliability Coordination — Responsibilities and Authorities

There have been many suggestions for improving these standards to ensure that each requirement is written so that it is clear and enforceable; to provide greater clarity to the applicability of each requirement (particularly in EOP-001 through EOP-003); and to add technically sound requirements for load shedding programs.

Please briefly describe your experience and qualifications directly related to the issues to be addressed by the Emergency Operations SAR Drafting Team. We are seeking a cross section of the industry to participate on the team, but in particular are seeking individuals who collectively have experience in real time operations (especially working for the Reliability Coordinator, Transmission Operator and Balancing Authority) and experience in establishing and testing load shedding programs.

Are you currently a member of any NERC or Regional Entity SAR or standard drafting team? If yes, please list each team here.

☐ No

☐ Yes:

Have you previously worked on any NERC or Regional Entity SAR or standard drafting teams? If yes, please list them here.

☐ No

☐ Yes:

Please identify the NERC Reliability Region(s) in which your company operates and for which you are able to represent your company's position relative to the applicable issues while serving on the SAR drafting team:

☐ ERCOT	☐ MRO	☐ RFC	☐ SPP
☐ FRCC	☐ NPCC	☐ SERC	☐ WEC

☐ Not Applicable or None of the Above

Please identify the Industry Segment(s) for which you are able to represent on behalf of

your company while serving on the SAR drafting team:	
☐	1 — Transmission Owners
☐	2 — RTOs and ISOs
☐	3 — Load-serving Entities
☐	4 — Transmission-dependent Utilities
☐	5 — Electric Generators
☐	6 — Electricity Brokers, Aggregators, and Marketers
☐	7 — Large Electricity End Users
☐	8 — Small Electricity End Users
☐	9 — Federal, State, and Provincial Regulatory or other Government Entities
☐	10 — Regional Reliability Organizations and Regional Entities
☐	Not applicable

Which of the following Functional Entities[1] do you have expertise or responsibilities for which you are able to represent on behalf of your company while serving on the SAR drafting team:

☐ Balancing Authority	☐ Planning Coordinator
☐ Compliance Enforcement Authority	☐ Transmission Operator
☐ Distribution Provider	☐ Transmission Owner
☐ Generator Operator	☐ Transmission Planner
☐ Generator Owner	☐ Transmission Service Provider
☐ Interchange Authority	☐ Purchasing-selling Entity
☐ Load-serving Entity	☐ Resource Planner
☐ Market Operator	☐ Reliability Coordinator

Please provide the names and contact information for two references who could attest to your technical qualifications and your ability to work well in a group which you give us permission to contact in the event it is deemed necessary to do so.

Name and Title:		Office Telephone:	
Organization:		E-mail:	
Name and Title:		Office Telephone:	
Organization:		E-mail:	

[1] These functions are defined in the NERC Functional Model, which is available on the NERC Web site.

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RELIABILITY CORPORATION

Standards Announcement

Standards Authorization Request (SAR) Comment and Drafting Team Nomination Periods Open

Project 2009-03 Emergency Operations

Now available at: http://www.nerc.com/filez/standards/Project2009-03_Emergency_Operations.html

Nominations for SAR Drafting Team (through December 18, 2009)

The Standards Committee is seeking industry experts to serve on the Emergency Operations SAR Drafting Team (see project background below). The SAR drafting team will assist the requester in further developing the SAR and considering stakeholder comments.

If you are interested in serving on this SAR drafting team, please complete the following electronic nomination form **by December 18, 2009**: https://www.nerc.net/nercsurvey/Survey.aspx?s=f518d336e6d640188ab1e3c37099b8b6

Comment Period (through January 15, 2010)

The Standards Committee has posted a proposed SAR for a 30-day comment period **ending on January 15, 2010**.

Please use this electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Lauren Koller at Lauren.Koller@nerc.net. An off-line, unofficial copy of the comment form is posted on the project page (see project background below).

Project Background

This project involves reviewing and revising the following four standards to eliminate redundancy, identify requirements that should be moved, eliminate requirements that do not support bulk power system reliability, improve clarity and measurability, and remove ambiguity:

EOP-001 — Emergency Operations Planning
EOP-002 — Capacity and Energy Emergencies
EOP-003 — Load Shedding Plans
IRO-001 — Reliability Coordination — Responsibilities and Authorities

The three EOP standards may be merged into a single standard, and there are some requirements in IRO-001 that may be improved and merged into the new EOP standard. The development may include other improvements to the standards deemed appropriate by the drafting team, with the consensus of stakeholders, consistent with establishing high quality, enforceable, and technically sufficient bulk power system reliability standards.

The project will require close coordination with two other drafting teams. The Operations Communications Protocols drafting team is working on a set of requirements for a new standard (COM-003-1) that references the use of Alert Levels, including those alert levels included in EOP-002-2. The Reliability Coordination SDT is working on a set of revisions to IRO-001-1 that includes retirement of several requirements.

Project page: http://www.nerc.com/filez/standards/Project2009-03_Emergency_Operations.html

Standards Development Process

The Reliability Standards Development Procedure contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance,
please contact Shaun Streeter at shaun.streeter@nerc.net or at 609.452.8060.

Standard Authorization Request Form

Title of Proposed Standard:	Emergency Operations (Project 2009-03)
Request Date	October 30, 2009
SC Approval Date	December 3, 2009
Modified Date	November 5, 2010

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)	
Name	Al McMeekin	☐	New Standard
Primary Contact	Al McMeekin	X	Revision to existing Standard
Telephone Fax	803-530-1963 803-957-4045	X	Withdrawal of existing Standard
E-mail	al.mcmeekin@nerc.net	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

Applicable Standards and Interpretation Projects:

- EOP-001-0 — Emergency Operations Planning
- EOP-001-1 — Emergency Operations Planning
- EOP-001-2 — Emergency Operations Planning
- EOP-002-2 — Capacity and Energy Emergencies
- EOP-002-2.1 — Capacity and Energy Emergencies
- EOP-002-3 — Capacity and Energy Emergencies
- EOP-003-1 — Load Shedding Plans
- EOP-003-2 — Load Shedding Plans
- Project 2007-23 — Violation Severity Levels
- Project 2010-INT-04 Interpretation of EOP-001-1 R2.4
- Project 2009-28 Interpretation of EOP-001-1 and EOP-001-2 Requirement R2.2
- Project 2008-09 Interpretation for EOP-001-0, R1
- Project 2008-07 Interpretation EOP-002-2, R6.3 and R7.1

The EOP standards in the list above shall be clarified individually, reorganized, or merged into a single standard. IRO-001 was originally a part of this project but has been removed because all of the issues and directives associated with that standard have been addressed by the Reliability Coordination SDT, Project 2006-06.

The development shall incorporate the NERC BOT approved interpretations, FERC directives, and other improvements to the standards deemed appropriate by the drafting team consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The industry needs standards that are technically accurate, clearly written so as to leave no confusion as to what a requirement means, and support the overall goal of ensuring bulk power system reliability. For the applicable entities to effectively comply, measurable and enforceable standards must be reasonable, clear and unambiguous minimizing the need for interpretation. Users, owners, and operators of the bulk power system should have no doubts with regards to what is required and who it is required of. Modifying these standards will eliminate requirements that do not impact the bulk power system and remove redundant requirements.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

Many of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process; suggestions for improvement have been submitted by stakeholders, other drafting teams, and FERC staff. The drafting team will consider these comments throughout its review of the standards. Options for the proposed changes are to:

- Modify the requirement to improve its clarity and measurability while removing ambiguity,
- Move the requirement (into another SAR or Standard or to the certification process)
- Eliminate the requirement (either because it is redundant or because it doesn't support bulk power system reliability).

The standard drafting team will review the associated items in what is termed the "NERC Standards Issues Database (Issues Database)." The Issues Database is used by the NERC standards program staff to track the issues and concerns identified with a particular standard. Prior to the development of the Issues Database, the Standard Review Form was utilized to capture all issues referencing a particular standard. The Standard Review Forms and the Issues Database excerpts applicable to these standards are listed in (Attachment 1).
The standard drafting team will also review the assigned standards and modify them to conform to the latest version of NERC's Standard Processes Manual, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure as described in the "Global Improvements" section of Volume I of the *Reliability Standards Development Plan* (Applicable sections of the Global Improvements section have been provided in Attachment2).

This project will require the standard drafting team to coordinate with NAESB to ensure the reliability standard does not have any undue, adverse impact on business practices or competition, and to coordinate with the drafting teams that are already in place and have proposed requirements that interface with some of the EOP requirements (includes the Balancing Authority Reliability Based Control SDT, the Operations Communications Protocols SDT, and the Underfrequency Load Shedding SDT).

Additionally, FERC directives from Order 693 pertaining to these standards must be addressed.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

This project involves reviewing and revising the referenced standards:

For each existing requirement, the drafting team will work with stakeholders and:
- Eliminate redundancy in the requirements.
- Identify requirements that should be moved.
- Eliminate requirements that do not support bulk power system reliability.
- Improve clarity and measurability.
- Remove ambiguity from the requirements.

EOP-001, EOP-002, and EOP-003 were Version 0 standards with minimal updates. They each have requirements with applicabilities that are inconsistent with the functional model, as well as various words or elements that need clarification.

The Operations Communications Protocols SDT is working on a set of requirements for a new standard (COM-003-1) that references the use of Alert Levels, including those alert levels included in EOP-002-2. Close coordination between the two projects will be required.

The Underfrequency Load Shedding SDT modified EOP-003-1 and the new version EOP-003-2 has been approved by the NERC BOT. EOP-003-2 now addresses both manual load shed and automatic UVLS. This DT is considering separating the automatic UVLS from the manual load shed requirements. The manual load shed requirements would be incorporated into the revised or new EOP standard while the automatic UVLS would remain in the newly revised EOP-003-3.

The Balancing Authority Reliability Based Control SDT references modifying EOP-002-2, Requirement R5 after BAL-007-1 through BAL-009-1 become effective. Close coordination between the two projects will be required.

To ensure consistency, NERC staff will coordinate with any SDT that incorporates the pertinent EOP standards in their scope.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
X	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
X	Transmission Owner	Owns and maintains transmission facilities.
X	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
X	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
X	Distribution Provider	Delivers electrical energy to the End-use customer.
X	Generator Owner	Owns and maintains generation facilities.
X	Generator Operator	Operates generation unit(s) to provide real and reactive power.
X	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
X	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
X ☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
X	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
X	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
COM-003-1	Contains pre-defined system condition terminology for verbal and written Interoperability Communications.

Related SARs

SAR ID	Explanation
Project 2007-02	Operations Communications Protocols SDT is working on a set of requirements for a new standard (COM-003-1) that references the use of Alert Levels, including those alert levels included in EOP-002-2.
Project 2007-01	The Underfrequency Load Shedding SDT is working on a revision to EOP-003-1, proposed EOP-003-2.
Project 2010-14	The Balancing Authority Reliability-based Control SDT references EOP-003-1 in its project scope.

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

SAR for Project 2009-03 – Emergency Operations
Attachment 1

Relevant Issues from NERC Standards Issues Database

Source	Standard No.	Project No	Language
Frank Gaffney (FMPA) RSDP Input	EOP-001-0	2009-03	The NERC Glossary of terms defines a TOP as: "the entity responsible for the reliability of its 'local' transmission system, and that operates or directs the operations of the transmission facilities." With this definition in mind, why is the TOP made responsible for EOP-001-1 R2.1: "develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity?"
Frank Gaffney (FMPA) RSDP Input	EOP-001-0	2009-03	The NERC Glossary of terms defines a BA as: "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." In other words, responsible for supply and demand balance in the operating horizon. With this definition in mind, why is the BA responsible for EOP-001-1 R2.2 "Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system"?
Frank Gaffney (FMPA) RSDP Input	EOP-001-0	2009-03	With regard to requirement R2, why is the BA responsible for Under Frequency Load Shedding (UFLS) when PRC-006-0 and PRC-007-0 make it the responsibility of the Regional Entities, the TOPs, the Distribution Providers and the LSEs? Why is the BA responsible for Under Voltage Load Shedding (UVLS) when the responsibility should probably be just the TOP's? Isn't this requirement redundant with PRC-006-0 and PRC-007-0?
Frank Gaffney (FMPA) RSDP Input	EOP-001-0	2009-03	Requirement R4 (and by reference Attachment 1-EOP-001-0) is applicable to both the Transmission Operator and Balancing Authority but includes items that are not applicable to the TOP and are only applicable to the BA, e.g., why is a TOP responsible for fuel supply? Why is a TOP responsible for R6.2 concerning emergency energy? Why is a TOP responsible for fuel supply in R6.4, and why is the TOP responsible for arranging energy delivery?
Frank Gaffney (FMPA) RSDP Input	EOP-003-1	2009-03	Requirement R2 of EOP-003-1 states: “Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.” The standards drafting team for Project 2007-01 Underfequency Load Shedding should consider modifying this requirement as part of their project.
Real-time Best Practices Standards	EOP-001-0	2009-03	Establish document plans and procedures for conservative operations

Study Group			
FERC's December 20, 2007 and April 4, 2008 Orders	EOP-002-2	2009-03	On March 4, 2008, NERC submitted a compliance filing in response to a December 20, 2007 Order, in which the Commission reversed a NERC decision to register three retail power marketers to comply with Reliability Standards applicable to load serving entities (LSEs) and directed NERC to submit a plan describing how it would address a possible "reliability gap" that NERC asserted would result if the LSEs were not registered. NERC's compliance filing included the following proposal for a short-term plan and a long-term plan to address the potential gap: · Short-term: Using a posting and open comment process, NERC will revise the registration criteria to define "Non-Asset Owning LSEs" as a subset of Load Serving Entities and will specify the reliability standards applicable to that subset. · Longer-term: NERC will determine the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers and process them through execution of the three-year Reliability Standards Development Plan. In this revised Reliability Standards Development Plan, NERC is commencing the implementation of its stated long-term plan to address the issues surrounding accountability for loads served by retail marketers/suppliers. The NERC Reliability Standards Development Procedure will be used to identify the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. Specifically, the following description has been incorporated into the scope for affected projects in this revised Reliability Standards Development Plan that includes a standard applicable to Load Serving Entities: Source: FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 Issue: In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the ReliabilityFirst (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: · FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf) · NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), · FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and · NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.
Real-time Best Practices Standards Study Group	EOP-003-1	2009-03	Provide the location, Real-time status, and MWs of Load available to be shed.

FERC's December 20, 2007 and April 4, 2008 Orders	IRO-001-1	2009-03	On March 4, 2008, NERC submitted a compliance filing in response to a December 20, 2007 Order, in which the Commission reversed a NERC decision to register three retail power marketers to comply with Reliability Standards applicable to load serving entities (LSEs) and directed NERC to submit a plan describing how it would address a possible "reliability gap" that NERC asserted would result if the LSEs were not registered. NERC's compliance filing included the following proposal for a short-term plan and a long-term plan to address the potential gap: · Short-term: Using a posting and open comment process, NERC will revise the registration criteria to define "Non-Asset Owning LSEs" as a subset of Load Serving Entities and will specify the reliability standards applicable to that subset. · Longer-term: NERC will determine the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers and process them through execution of the three-year Reliability Standards Development Plan. In this revised Reliability Standards Development Plan, NERC is commencing the implementation of its stated long-term plan to address the issues surrounding accountability for loads served by retail marketers/suppliers. The NERC Reliability Standards Development Procedure will be used to identify the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. Specifically, the following description has been incorporated into the scope for affected projects in this revised Reliability Standards Development Plan that includes a standard applicable to Load Serving Entities: Source: FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 Issue: In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the ReliabilityFirst (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: · FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf) · NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), · FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and · NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.

Standard Review Form Project 2009-03 — Emergency Operations	
Standard #	**Title**
EOP-001-1	Emergency Operations Planning

Issues	FERC Order 693 Disposition: Approved with modification • Include reliability coordinators as an applicable entity. • Consider Southern California Edison's and Xcel's suggestions in the standard development process. • Clarify that the 30-minute requirement in requirement R2 to state that load shedding should be capable of being implemented as soon as possible but no more than 30 minutes. • Includes definitions of system states (e.g. normal, alert, emergency), criteria for entering into these states. And the authority that will declare them. • Consider a pilot program (field test) for the system states proposal. • Clarifies that the actual emergency plan elements, and not the "for consideration" elements of Attachment 1, should be the basis for compliance. V1 Industry Comments • Combine R4 & R5 • Revise R5 • Measures are really data retention requirements VRF comment • R1 – primarily administrative Other • Modify standard to conform with the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure.

Standard Review Form Project 2009-03 — Emergency Operations	
Standard #	**Title**
EOP-002-2	Capacity and Energy Emergencies
Issues	FERC Order 693 Disposition: Approved with modification • Address emergencies resulting not only from insufficient generation but also insufficient transmission capability, particularly as it affects the implement of the capacity and energy emergency plan. • Include all technically feasible resource options, including demand response and generation resources • Ensure the TLR procedure is not used to mitigate actual IROL violations.

	V0 Industry Comments • R3 should be applied to RC's • Re-wording in R7 • Measures aren't really measures but requirements • L4 non-compliance needs definition of time frame • Several wording changes to Attachment • Compliance not mapped to requirements VRF comments • R9 - This is a commercial and administrative ordering of curtailments. Other • Modify standard to conform with the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure.

Standard Review Form Project 2009-03 — Emergency Operations	
Standard #	**Title**
EOP-003-1	Load Shedding Plans
Issues	FERC Order 693 Disposition: Approved with modification • Develop specific minimum load shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented based on overarching nationwide criteria that take into account system characteristics. • Require periodic drills of simulated load shedding. • Suggest a review of industry best practices in determining nationwide criteria. • Consider comments from APPA and ISO-NE in the standards development process. V0 Industry Comments • Move implementation requirements • Re-state purpose • Move to Policy 5 & 9 • Add UVLS

	VRF comments • R4 – Needs clarification • R6 - Failure to shed load in this condition can inhibit restoration. Other • Modify standard to conform with the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure.

SAR for Project 2009-03 – Emergency Operations
Attachment 2

Global Improvements

The standard drafting team is expected to review the assigned standards and modify the standards to conform to the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure as described in this "Global Improvements" section.

Statutory Criteria

In accordance with Section 215 of the Federal Power Act, FERC may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that "the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest."

The first three of these criteria can be addressed in large part by the diligent adherence to NERC's *Reliability Standards Development Procedure*, which has been certified by the ANSI as being open, inclusive, balanced, and fair. Users, owners, and operators of the bulk power system that must comply with the standards, as well as the end-users who benefit from a reliable supply of electricity and the public in general, gain some assurance that standards are just, reasonable, and not unduly discriminatory or preferential because the standards are developed through an ANSI-accredited procedure.

The remaining portion of the statutory test is whether the standard is "in the public interest." Implicit in the public-interest test is that a standard is technically sound and ensures a level of reliability that should be reasonably expected by end-users of electricity. Additionally, each standard must be clearly written, so that bulk power system users, owners, and operators are informed of the expected behavior or have knowledge of the expected behavior. Ultimately, the standards should be defensible in the event of a governmental authority review or court action that may result from enforcing the standard and applying a financial penalty.

The standards must collectively provide a comprehensive and complete set of technically sound requirements that establish an acceptable threshold of performance necessary to ensure the reliability of the bulk power system. "An adequate level of reliability" would argue for both a complete set of standards addressing all aspects of bulk power system design, planning, and operation that materially affect reliability, and for the technical efficacy of each standard. The Commission directed NERC to define the term, "adequate level of reliability" as part of its January 18, 2007 Order on Compliance Filing. Accordingly, NERC's Operating and Planning Committees prepared the definition and the NERC Board approved it at its February 2008 meeting for filing with regulatory authorities. The NERC Standards Committee was then tasked to integrate the definition into the development of future reliability standards.

Quality Objectives

To achieve the goals outlined above, NERC has developed 10 quality objectives for the development of reliability standards. Drafting teams working on assigned projects are charged to ensure their work adheres to the following quality objectives:

1. **Applicability —** Each reliability standard shall clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted. Such functional classes[1] include: ERO, Regional Entities, reliability coordinators, balancing authorities, transmission operators, transmission owners, generator operators, generator owners, interchange authorities, transmission service providers, market operators, planning coordinators, transmission planners, resource planners, load-serving entities, purchasing-selling entities, and distribution providers. Each reliability standard that does not apply to the entire North American bulk power system shall also identify the geographic applicability of the standard, such as an interconnection, or within a regional entity area. The applicability section of the standard should also include any limitations on the applicability of the standard based on electric facility characteristics, such as a requirement that applies only to the subset of distribution providers that own or operate underfrequency load shedding systems.

2. **Purpose —** Each reliability standard shall have a clear statement of purpose that shall describe how the standard contributes to the reliability of the bulk power system.

3. **Performance Requirements —** Each reliability standard shall state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest. Each requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for bulk power system reliability, taking account of the costs and benefits of implementing the proposal.

4. **Measurability —** Each performance requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement. Each performance requirement shall have one or more associated measures used to objectively evaluate compliance with the requirement. If performance results can be practically measured quantitatively, metrics shall be provided within the requirement to indicate satisfactory performance.

[1] These functional classes of entities are derived from NERC's Reliability Functional Model. When a standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in Reliability Standards.

5. **Technical Basis in Engineering and Operations —** Each reliability standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.
6. **Completeness —** Each reliability standard shall be complete and self-contained. The standards shall not depend on external information to determine the required level of performance.
7. **Consequences for Noncompliance —** Each reliability standard shall make clearly known to the responsible entities the consequences of violating a standard, in combination with guidelines for penalties and sanctions, as well as other ERO and Regional Entity compliance documents.
8. **Clear Language —** Each reliability standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.
9. **Practicality —** Each reliability standard shall establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.
10. **Consistent Terminology —** Each reliability standard, to the extent possible, shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards Development Process.

In addition to these factors, standard drafting teams also contemplate the following factors the Commission uses to approve a proposed reliability standard as outlined in Order No. 672. A standard proposed to be approved:

1. **Must be designed to achieve a specified reliability goal**
   "321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of bulk power system facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to cyber security protection."

   "324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal.
   Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and

lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons."

2. **Must contain a technically sound method to achieve the goal**
"324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal.

Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons."

3. **Must be applicable to users, owners, and operators of the bulk power system, and not others**
"322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others."

4. **Must be clear and unambiguous as to what is required and who is required to comply**
"325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability."

5. **Must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation**
"326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply."

6. **Must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner**
"327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner."

7. **Should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect "best practices" without regard to implementation cost**
"328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently."

8. **Cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect bulk power system reliability**
"329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator"—if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability."

9. **Costs to be considered for smaller entities but not at consequence of less than excellence in operating system reliability**
"330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it."

10. **Must be designed to apply throughout North American to the maximum extent achievable with a single reliability standard while not favoring one area or approach**
"331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard."

11. **No undue negative effect on competition or restriction of the grid**
"332. As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue

negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another."

12. Implementation time

"333. In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability."

13. Whether the reliability standard process was open and fair

"334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission."

14. Balance with other vital public interests

"335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard."

15. Any other relevant factors

"323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed."

"337. In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. The Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed reliability standard."

Issues Related to the Applicability of a Standard

In Order No. 672, the Commission states that a proposed reliability standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the bulk power system must know what they are required to do to maintain reliability. Section 215(b) of the FPA requires all "users, owners and operators of the bulk power system" to comply with Commission-approved reliability standards.

The term "users, owners, and operators of the bulk power system" defines the statutory applicability of the reliability standards. NERC's Reliability Functional Model (Functional Model) further refines the set of users, owners, and operators by identifying categories of functions that entities perform so the applicability of each standard can be more clearly defined. Applicability is clear if a standard precisely states the applicability using the functions an entity performs. For example, "Each Generator Operator shall verify the reactive power output capability of each of its generating units" states clear applicability compared with a standard that states "a bulk power system user shall verify the reactive power output capability of each generating unit." The use of the Functional Model in the standards narrows the applicability of the standard to a particular class or classes of bulk power system users, owners, and operators. A standard is more clearly enforceable when it narrows the applicability to a specific class of entities than if the standard simply references a wide range of entities, e.g., all bulk power system users, owners, and operators.

In determining the applicability of each standard and the requirements within a standard, the drafting team should follow the definitions provided in the NERC Glossary of Terms Used in Reliability Standards and should also be guided by the Functional Model.

In addition to applying definitions from the Functional Model, the revised standards must address more specific applicability criteria that identify only those entities and facilities that are material to bulk power system reliability with regard to the particular standard.

The drafting team should review the registration criteria provided in the NERC Statement of Compliance Registry Criteria, which is the criteria for applicability. The registration criteria identify the criteria NERC uses to identify those entities responsible for compliance to the reliability standards. Any deviations from the criteria used in the Statement of Compliance Registry Criteria must be identified in the applicability section of the. It is also important to note that standard drafting teams cannot set the applicability of reliability standards to extend to entities beyond the scope established by the criteria for inclusion on NERC's Compliance Registry. This is expressly prohibited by Commission Order No. 693-A.

The goal is to place obligations on the entities whose performance will impact the reliability of the bulk power system, but to avoid painting the applicability with such a broad brush that entities are obligated even when meeting a requirement will make no material contribution to bulk power system reliability.

Every entity class described in the Functional Model performs functions that are essential to the reliability of the bulk power system. This point is best highlighted with the example that might be the most difficult to understand, the inclusion of distribution providers. Section 215 of the FPA specifically excludes facilities used in the local distribution of electric energy. Nonetheless, some of the NERC standards apply to a class of entities called Distribution Providers. Distribution Providers are covered because, although they own and operate facilities in the local distribution of electric energy, they also perform functions affecting and essential to the reliability of the bulk power system. With regard to these facilities and functions that are material to the reliability of the bulk power system, a distribution provider is a bulk power system user. For example, requirements for distribution providers in the reliability standards apply to the underfrequency load shedding relays that are maintained and operated within the distribution system to protect the reliability of the bulk power system. There are also requirements for distribution providers to provide demand forecast information for the planning of reliable operations of the bulk power system.

A similar line of thinking can apply to every other entity in the Functional Model, including Load-serving Entities and Purchasing-selling Entities, which are users of the bulk power system to the extent they transact business for the use of transmission service or to transfer power across the bulk power system. NERC has specific requirements for these entities based on how these uses may impact the reliability of the bulk power systems. Other functional entities are more obviously bulk power system owners and operators, such as Reliability Coordinators, Transmission Owners and Operators, Generator Owners and Operators, Planning Coordinators, Transmission Planners, and Resource Planners. It is the extent to which these entities provide for a reliable bulk power system or perform functions that materially affect the reliability of the bulk power system that these entities fall under the jurisdiction of Section 215 of the FPA and the reliability standards. The use of the Functional Model simply groups these entities into logical functional areas to enable the standards to more clearly define the applicability.

Issues Related to Regional Entities and Reliability Organizations

Because of the transition from voluntary reliability standards to mandatory reliability standards, confusion has occurred over the distinction between Regional Entities and Regional Reliability Organizations. The regional councils have traditionally been the owners and members of NERC. They have been referred to as Regional Reliability Organizations in the Functional Model and in the reliability standards. In an era of voluntary standards and guides, it was acceptable that a number of the standards included requirements for Regional Reliability Organizations to develop regional criteria, procedures, and plans, and included requirements for entities within the region to follow those requirements. Section 215 of the FPA introduced a new term, called “Regional Entity.”

Regional Entities have specific delegated authorities, under agreements with NERC, to propose and enforce reliability standards within the region, and to perform other functions in support of the electric reliability organization. The former Regional Reliability Organizations have entered into delegation agreements with NERC to become Regional Entities for this purpose.

With regard to distinguishing between the terms Regional Reliability Organizations and Regional Entities, the following guidance should be used. The corporations that provide regional reliability services on behalf of their members are Regional Reliability Organizations. NERC may delegate to these entities a set of regional entity functions. The Regional Reliability Organizations perform delegated regional entity functions much like NERC is the organization that performs the ERO function. Regional Reliability Organizations may do things other than their statutory or delegated regional entity functions.

With the regions having responsibility for enforcement, it is no longer appropriate for the regions to be named as responsible entities within the standards. The plan calls for removing requirements from the standards that refer to Regional Reliability Organizations, either by deleting the requirements or redirecting the responsibilities to the most applicable functions in the Functional Model, such as Planning Coordinators, Reliability Coordinators, or Resource Planners. In instances where a regional standard or criteria are needed, the ERO may direct the Regional Entities to propose a regional standard in accordance with ERO Rule 312.2, which states NERC, may "direct regional entities to develop regional reliability standards." There is no need to have a NERC standard that directs the regions to develop a regional standard. NERC standards should only include requirements for Regional Entities in those rare instances where the regions have a specific operational, planning, or security responsibility. In this case, Regional Entities (or NERC) may be noted as the applicable entity. However, these Regional Entities (or NERC) are held accountable for compliance to these requirements through NERC's Rules of Procedure that, by delegation agreement, extend to the Regional Entities. The Regional Entities are not users, owners, or operators of the bulk power system and cannot be held responsible for compliance through the compliance monitoring and enforcement program. However, NERC and the Regional Entities can be held by the Commission to be in violation of its rules of procedure for failing to comply with the standards requirements to which it is assigned.

Issues Related to Ambiguity

Drafting teams should strive to remove all potential ambiguities in the language of each standard, particularly in the performance requirements. Redundancies should also be eliminated.

Specifically, each performance requirement must be written to include four elements:

- **Who —** defines which functional entity or entities are responsible for the requirements, including any narrowing or qualifying limits on the applicability to or of an entity, based on material impact to reliability.

- **Shall do what —** describes an action the responsible entity must perform.
- **To what outcome** — describes the expected, measurable outcome from the action.
- **Under what conditions** — describes specific conditions under which the action must be performed. If blank, the action is assumed to be required at all times and under all conditions.

Each requirement should identify a product or activity that makes a definite contribution to reliability.

Drafting teams should focus on defining measurable outcomes for each requirement, and not on prescribing *how* a requirement is to be met. While being more prescriptive may provide a sense of being more measurable, it does not add reliability benefits and may be inefficient and restrict innovation.

Issues Related to Technical Adequacy

In May 2006, the Commission issued an assessment on the then proposed reliability standards. The Commission noted under a "technical adequacy" section that requirements specified in some standards may not be sufficient to ensure an adequate level of reliability. While Order No. 672 notes that "best practice" may be an inappropriately high standard, it also warns that a "lowest common denominator" approach will not be acceptable if it is not sufficient to ensure system reliability.

Each standard should clearly meet the statutory test of providing an adequate level of reliability to the bulk power system. Each requirement should be evaluated and the bar raised as needed, consistent with good practice and as supported by consensus.

Issues Related to Compliance Elements

Each reliability standard includes a section to address measures and a section to address compliance. The Uniform Compliance Monitoring and Enforcement Guidelines, ERO Sanctions Guidelines, and Compliance Registry Criteria have been modified and have been approved by the Commission. As each standard is revised, or as new standards are developed, drafting teams need to familiarize themselves with these documents to ensure that each standard proposed for ballot is in a format that includes all the elements needed to support reliability and to ensure that the standard can be enforced for compliance.

The compliance-related elements of standards that may need to be modified to meet the latest approved versions of the various compliance documents noted above include the following:

- Each requirement must have an associated Violation Risk Factor.

- Each requirement must have an associated Time Horizon.
- The term, "Compliance Monitor" has been replaced with the term, "Compliance Enforcement Authority." Either the Regional Entity or the ERO may serve as the compliance enforcement authority. For most standards, the Regional Entity will serve as the compliance enforcement authority. In the situation where a Regional Entity has authority over a reliability coordinator, for example, the ERO will serve as the compliance enforcement authority to eliminate any conflict of interest.
- The eight processes used to monitor and enforce compliance have been assigned new names.
    - Compliance Audits
    - Self-Certifications
    - Spot Checking
    - Compliance Violation Investigations
    - Self-Reporting
    - Periodic Data Submittals
    - Exception Reporting
    - Complaints
- The audit cycles for various entities have been standardized so that the Reliability Coordinator, Transmission Operator, and Balancing Authority will undergo a routine audit to assess compliance with each applicable requirement once every three years while all other responsible entities will undergo a routine audit once every six years.
- Levels of Non-compliance have been replaced with "Violation Severity Levels."

All requirements are subject to compliance audits, self-certification, spot checking, compliance violation investigations, self-reporting and complaints. Only a subset of requirements is subject to monitoring through periodic data submittals and exception reporting.

Measures: While a measure can be used for more than one requirement, there must be at least one measure for each requirement. A measure states what a responsible entity must have or do to demonstrate compliance to a third party, i.e., the compliance enforcement authority. Measures are "yardsticks" used to evaluate whether required performance or outcomes have been achieved. Measures do not add new requirements or expand the details of the requirements. Each measure shall be tangible, practical, and objective. A measure should be written so that achieving full compliance with the measure provides the compliance monitor with the necessary and sufficient information to demonstrate that the associated requirement was met by the responsible entity. Each measure should clearly refer to the requirement(s) to which it applies.

Violation Severity Levels: The Violation Severity Levels (formerly known as Levels of Non-Compliance) indicate how severely an entity violated a requirement. Historically, there has been confusion about Levels of Non-Compliance. Some of the previously existing Levels of Non-Compliance incorporate reliability-related risk impacts or consequences. Going forward, the risk or consequences component should be addressed only by the Violation Risk Factor, while the Violation Severity Levels should only be used to categorize how badly the requirement was violated.

Criteria for determining which VSL to use:
It is preferable to have four VSLs representing a spectrum of performance, but where that does not work; the VSLs should be defensible in supporting the criteria in the table below.

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

Violation Risk Factors: Each drafting team is also instructed to develop a Violation Risk Factor for each requirement in a standard in accordance with the following definitions:

- **High Risk Requirement** — A requirement that, if violated, could directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures, or could place the bulk power system at an unacceptable risk of instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures, or could place the bulk power system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.
- **Medium Risk Requirement** — A requirement that, if violated, could directly affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or a requirement in a

planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk power system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

- **Lower Risk Requirement** — A requirement that is administrative in nature and, a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. A requirement that is administrative in nature; or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system.

Time Horizons: The drafting team must also indicate the time horizon available for mitigating a violation to the requirement:

- **Long-term planning —** a planning horizon of one year or longer.
- **Operations planning —** operating and resource plans from day ahead up to and including seasonal.
- **Same-day operations —** routine actions required within the timeframe of a day, but not real time.
- **Real-time operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations assessment —** follow-up evaluations and reporting of real time operations.

Note that some requirements occur in multiple time horizons, and it is acceptable to have more than one time horizon for a single requirement.

The drafting team should seek input and review of all measures and compliance information from the compliance elements drafting team members assigned to support each standard drafting team or from the NERC compliance staff.

Coordination with NAESB

Many of the existing NERC standards are related to business practices, although their primary purpose is to support reliability. Reliability standards, business practices, and commercial interests are inextricably linked.

It would be safe to conclude that every reliability standard has some degree of commercial impact and therefore impacts competition. The statutory test to be applied by the Commission is whether the reliability standard has an "undue adverse effect" on competition.

NERC has taken several steps to ensure its reliability standards do not have any undue, adverse impact on business practices or competition. First, NERC coordinates the development of all standards with the North American Energy Standards Board (NAESB). In addition to this formal process, drafting teams work with NAESB groups to ensure effective coordination of wholesale electric business practice standards and reliability standards. NERC and NAESB follow their procedure for the joint development of standards in areas that have both reliability and business practice elements. This procedure is being implemented for all standards in which the reliability and business practice elements are closely related, thereby making joint development a more efficient approach.

This project will require close coordination and joint development with NAESB as there are anticipated revisions to these standards that may need new or revised associated business practices.

To ensure each reliability standard does not have an undue adverse effect on competition, NERC requires that each standard meet the following criteria:

- Competition — A reliability standard shall not give any market participant an unfair competitive advantage.
- Market Structures — A reliability standard shall neither mandate nor prohibit any specific market structure.
- Market Solutions — A reliability standard shall not preclude market solutions to achieve compliance with that standard.
- Commercially Sensitive Information — A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.

During the standards development process, each Standards Authorization Request (SAR) drafting team asks the following question to determine if there is a need to develop a business practice associated with the proposed standard:

- Are you aware of any associated business practices that we should consider with this SAR?

Each standard drafting team also asks the following question to determine if there is a potential conflict between a reliability standard and business practice:

- Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement? If yes, please identify the conflict.

Additional Considerations

Drafting teams should consider the following in reviewing and revising their assigned standards:

- **Title**: In general, the title should be concise and to the point. Care should be taken not to try to fully describe a standard through its title. The title should fit a single line in both the header and in the body of the standard.
- **Purpose**: The purpose should clearly state a benefit to the industry (value proposition) in fulfilling the requirements. The purpose should not simply state "the purpose is to develop a standard to…" The purpose should be tied to one or more of the reliability principles.
- **References**: Section (F) provides a place to list associated references that support implementation of the standard. Drafting teams may develop or reference supporting documents with approval of the Standards Committee.
- **Version histories**: Version histories should be expanded to include complete listings of what has been changed from version to version so that end-users can easily keep track of changes to standards. This will also serve as a type of audit trail for changes.

Resource Documents Used

NERC used several references when preparing this plan. These references provide detailed descriptions of the issues and comments that need to be considered by the drafting teams, which are included in the second volume of the work plan, as they work on the standards projects defined in the plan. The references include:

- FERC NOPR on Reliability Standards, October 20, 2006.
- FERC Staff Preliminary Assessment of Proposed Reliability Standards, May 11, 2006.
- FERC Order No. 693 Mandatory Reliability standards for the Bulk Power System, March 16, 2007.
- FERC Order No. 693-A Mandatory Reliability Standards for the Bulk Power System, July 19, 2007.
- FERC Order No. 890 Preventing Undue Discrimination and Preference in Transmission Service, February 16, 2007.
- Comments of the North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment of Reliability Standards, June 26, 2006.

- Comments of the North American Electric Reliability Corporation on Staff Preliminary Assessment of NERC Standards CIP-002 through CIP-009, February 12, 2007.
- Comments of the North American Electric Reliability Corporation on the Notice of Proposed Rulemaking for Facilities Design, Connections and Maintenance Reliability standards, September 19, 2007.
- Comments received during the development of Version 0 reliability standards.
- Consideration of comments of the Missing Compliance Elements drafting team.
- Consideration of comments of the Violation Risk Factors drafting team.
- Consideration of comments in the Phase III–IV standards.
- Comments received during industry comment period on work plan.
- Q&A for Standards and Compliance.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standard Authorization Request Form

Title of Proposed Standard:	Emergency Operations (Project 2009-03)
Request Date	October 30, 2009
SC Approval Date	December 3, 2009
Modified Date	November 5, 2010

SAR Requester Information		**SAR Type** (*Check a box for each one that applies.*)
Name Al McMeekin	☐	New Standard
Primary Contact Al McMeekin	X	Revision to existing Standard
Telephone 803-530-1963 Fax 803-957-4045	X	Withdrawal of existing Standard
E-mail al.mcmeekin@nerc.net	☐	Urgent Action

Purpose (Describe what the standard action will achieve in support of bulk power system reliability.)

Applicable Standards and Interpretation Projects:

- EOP-001-0 — Emergency Operations Planning
- EOP-001-1 — Emergency Operations Planning
- EOP-001-2 — Emergency Operations Planning
- EOP-002-2 — Capacity and Energy Emergencies
- EOP-002-2.1 — Capacity and Energy Emergencies
- EOP-002-3 — Capacity and Energy Emergencies
- EOP-003-1 — Load Shedding Plans
- ~~IRO~~EOP-003-2 — Load Shedding Plans
- Project 2007-23 — Violation Severity Levels
- Project 2010-INT-04 Interpretation of EOP-001-1 ~~— Reliability Coordination — Responsibilities~~R2.4
- Project 2009-28 Interpretation of EOP-001-1 and ~~Authorities~~EOP-001-2 Requirement R2.2
- Project 2008-09 Interpretation for EOP-001-0, R1
- Project 2008-07 Interpretation EOP-002-2, R6.3 and R7.1

The ~~first three~~EOP standards in the list above ~~may~~shall be clarified individually, reorganized, or merged into a single standard. ~~There are some requirements in IRO-001 that may be improved and merged into~~ IRO-001 was originally a part of this project but has been removed because all of the ~~new EOP~~ issues and directives associated with that standard have been addressed by the Reliability Coordination SDT, Project 2006-06.

The development ~~may include~~shall incorporate the NERC BOT approved interpretations, FERC directives, and other improvements to the standards deemed appropriate by the drafting team~~, with the consensus of stakeholders,~~ consistent with establishing high quality, enforceable and technically sufficient bulk power system reliability standards.

Industry Need (Provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)

The industry needs standards that are technically accurate, clearly written so as to leave no confusion as to what a requirement means, and support the overall goal of ensuring bulk power system reliability. For the applicable entities to effectively comply, measurable and enforceable standards must be reasonable, clear and unambiguous minimizing the need for interpretation. Users, owners, and operators of the bulk power system should have no doubts with regards to what is required and who it is required of. ~~Merging~~Modifying these standards will eliminate requirements that do not impact the bulk power system and remove redundant requirements.

Brief Description (Provide a paragraph that describes the scope of this standard action.)

Many of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process; suggestions for improvement have been submitted by stakeholders, other drafting teams, and FERC staff. The drafting team will consider these comments throughout its review of the standards. Options for the proposed changes are to:

- Modify the requirement to improve its clarity and measurability while removing ambiguity,
- Move the requirement (into another SAR or Standard or to the certification process)
- Eliminate the requirement (either because it is redundant or because it doesn't support bulk power system reliability).

The standard drafting team will review the associated items in what is termed the "NERC Standards Issues Database (Issues Database)." The Issues Database is used by the NERC standards program staff to track the issues and concerns identified with a particular standard. Prior to the development of the Issues Database, the Standard Review Form was utilized to capture all issues referencing a particular standard. The Standard Review Forms and the Issues Database excerpts applicable to these standards are listed in (Attachment 1).
The standard drafting team will also review the assigned standards and modify them to conform to the latest version of NERC's ~~Reliability~~ Standard~~s~~ ~~Development Procedure~~Processes Manual, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure as described in the "Global Improvements" section of Volume I of the *Reliability Standards Development Plan* (Applicable sections of the Global Improvements section have been provided in Attachment2).

This project will require the standard drafting team to coordinate with NAESB to ensure the reliability standard does not have any undue, adverse impact on business practices or competition, and to coordinate with the drafting teams that are already in place and have proposed requirements that interface with some of the EOP requirements (includes the Balancing Authority Reliability ~~Coordination~~Based Control SDT~~ and~~, the Operations Communications Protocols SDT, and the Underfrequency Load Shedding SDT).

Additionally, FERC directives from Order 693 pertaining to these standards must be addressed.

Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR.)

This project involves reviewing and revising the ~~four~~ referenced standards:

For each existing requirement, the drafting team will work with stakeholders and:
- Eliminate redundancy in the requirements.
- Identify requirements that should be moved.
- Eliminate requirements that do not support bulk power system reliability.
- Improve clarity and measurability~~, and remove ambiguity from the requirement~~.
- Remove ambiguity from the requirements.

EOP-001~~-1~~, EOP-002~~-2~~, and EOP-003~~-1~~ were Version 0 standards with minimal updates. They each have requirements with applicabilities that are inconsistent with the functional model, as well as various words or elements that need clarification. ~~IRO-001-1 has requirements with applicability and clarity issues that must be addressed and some requirements that may be moved to the new EOP standard(s).~~

The Operations Communications Protocols SDT is working on a set of requirements for a new standard (COM-003-1) that references the use of Alert Levels, including those alert levels included in EOP-002-2. Close coordination between the two projects will be required.

The ~~Reliability Coordination~~Underfrequency Load Shedding SDT modified EOP-003-1 and the new version EOP-003-2 has been approved by the NERC BOT. EOP-003-2 now addresses both manual load shed and automatic UVLS. This DT is ~~working on a set of revisions to IRO-001-1 that includes retirement of several~~considering separating the automatic UVLS from the manual load shed requirements. The manual load shed requirements would be incorporated into the revised or new EOP standard while the automatic UVLS would remain in the newly revised EOP-003-3.

The Balancing Authority Reliability Based Control SDT references modifying EOP-002-2, Requirement R5 after BAL-007-1 through BAL-009-1 become effective. Close coordination between the two projects will be required.

To ensure consistency, NERC staff will coordinate with any SDT that incorporates the pertinent EOP standards in their scope.

Reliability Functions

The Standard will Apply to the Following Functions *(Check box for each one that applies.)*		
☐	Reliability Assurer	Monitors and evaluates the activities related to planning and operations, and coordinates activities of Responsible Entities to secure the reliability of the bulk power system within a Reliability Assurer Area and adjacent areas.
X	Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
X	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within its portion of the Planning Coordinator's Area.
~~☐~~X	Transmission Owner	Owns and maintains transmission facilities.
X	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within the Transmission Planner Area.
X	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
X	Distribution Provider	Delivers electrical energy to the End-use customer.
~~☐~~X	Generator Owner	Owns and maintains generation facilities.
X	Generator Operator	Operates generation unit(s) to provide real and reactive power.
X	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
X	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Applicable Reliability Principles *(Check box for all that apply.)*	
X	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
X ☐	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
X	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
X	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
X	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
X	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
X	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles? *(Select 'yes' or 'no' from the drop-down box.)*
1. A reliability standard shall not give any market participant an unfair competitive advantage. Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure. Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard. Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards. Yes

Related Standards

Standard No.	Explanation
~~PER-002~~	~~Applicable personnel must be trained in restoration and blackstart procedures.~~
~~EOP-005~~	~~Contains TOP requirements for coordination of emergency plans with RC.~~
~~EOP-006~~	~~Contains RC requirements for coordination of emergency plans.~~
COM-003-1	Contains pre-defined system condition terminology for verbal and written Interoperability Communications.

Related SARs

SAR ID	Explanation
Project 2007-02	Operations Communications Protocols SDT is working on a set of requirements for a new standard (COM-003-1) that references the use of Alert Levels, including those alert levels included in EOP-002-2.
Project ~~2006-06~~2007-01	The ~~Reliability Coordination~~Underfrequency Load Shedding SDT is working on a ~~set of revisions~~revision to ~~IRO-001~~EOP-003-1, proposed EOP-003-2.
Project 2010-14	The Balancing Authority Reliability-based Control SDT references EOP-003-1 in ~~their~~its project scope.

Regional Variances

Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
SERC	
RFC	
SPP	
WECC	

SAR for Project 2009-03 – Emergency Operations
Attachment 1

Relevant Issues from NERC Standards Issues Database

Source	Standard No.	Project No	Language
Frank Gaffney (FMPA) RSDP Input	EOP-001-0	2009-03	The NERC Glossary of terms defines a TOP as: "the entity responsible for the reliability of its 'local' transmission system, and that operates or directs the operations of the transmission facilities." With this definition in mind, why is the TOP made responsible for EOP-001-1 R2.1: "develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity?"
Frank Gaffney (FMPA) RSDP Input	EOP-001-0	2009-03	The NERC Glossary of terms defines a BA as: "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." In other words, responsible for supply and demand balance in the operating horizon. With this definition in mind, why is the BA responsible for EOP-001-1 R2.2 "Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system"?
Frank Gaffney (FMPA) RSDP Input	EOP-001-0	2009-03	With regard to requirement R2, why is the BA responsible for Under Frequency Load Shedding (UFLS) when PRC-006-0 and PRC-007-0 make it the responsibility of the Regional Entities, the TOPs, the Distribution Providers and the LSEs? Why is the BA responsible for Under Voltage Load Shedding (UVLS) when the responsibility should probably be just the TOP's? Isn't this requirement redundant with PRC-006-0 and PRC-007-0?
Frank Gaffney (FMPA) RSDP Input	EOP-001-0	2009-03	Requirement R4 (and by reference Attachment 1-EOP-001-0) is applicable to both the Transmission Operator and Balancing Authority but includes items that are not applicable to the TOP and are only applicable to the BA, e.g., why is a TOP responsible for fuel supply? Why is a TOP responsible for R6.2 concerning emergency energy? Why is a TOP responsible for fuel supply in R6.4, and why is the TOP responsible for arranging energy delivery?
Frank Gaffney (FMPA) RSDP Input	EOP-~~001-0~~003-1	2009-03	Requirement R2 of EOP-003-1 states: “Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions.” The standards drafting team for Project 2007-01 Underfequency Load Shedding should consider modifying this requirement as part of their project.
Real-time Best Practices Standards	EOP-001-0	2009-03	Establish document plans and procedures for conservative operations

Study Group			
FERC's December 20, 2007 and April 4, 2008 Orders	EOP-002-2	2009-03	On March 4, 2008, NERC submitted a compliance filing in response to a December 20, 2007 Order, in which the Commission reversed a NERC decision to register three retail power marketers to comply with Reliability Standards applicable to load serving entities (LSEs) and directed NERC to submit a plan describing how it would address a possible "reliability gap" that NERC asserted would result if the LSEs were not registered. NERC's compliance filing included the following proposal for a short-term plan and a long-term plan to address the potential gap: · Short-term: Using a posting and open comment process, NERC will revise the registration criteria to define "Non-Asset Owning LSEs" as a subset of Load Serving Entities and will specify the reliability standards applicable to that subset. · Longer-term: NERC will determine the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers and process them through execution of the three-year Reliability Standards Development Plan. In this revised Reliability Standards Development Plan, NERC is commencing the implementation of its stated long-term plan to address the issues surrounding accountability for loads served by retail marketers/suppliers. The NERC Reliability Standards Development Procedure will be used to identify the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. Specifically, the following description has been incorporated into the scope for affected projects in this revised Reliability Standards Development Plan that includes a standard applicable to Load Serving Entities: Source: FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 Issue: In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the ReliabilityFirst (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: · FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf) · NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), · FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and · NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.
Real-time Best Practices Standards Study Group	EOP-003-1	2009-03	Provide the location, Real-time status, and MWs of Load available to be shed.

FERC's December 20, 2007 and April 4, 2008 Orders	IRO-001-1	2009-03	On March 4, 2008, NERC submitted a compliance filing in response to a December 20, 2007 Order, in which the Commission reversed a NERC decision to register three retail power marketers to comply with Reliability Standards applicable to load serving entities (LSEs) and directed NERC to submit a plan describing how it would address a possible "reliability gap" that NERC asserted would result if the LSEs were not registered. NERC's compliance filing included the following proposal for a short-term plan and a long-term plan to address the potential gap: · Short-term: Using a posting and open comment process, NERC will revise the registration criteria to define "Non-Asset Owning LSEs" as a subset of Load Serving Entities and will specify the reliability standards applicable to that subset. · Longer-term: NERC will determine the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers and process them through execution of the three-year Reliability Standards Development Plan. In this revised Reliability Standards Development Plan, NERC is commencing the implementation of its stated long-term plan to address the issues surrounding accountability for loads served by retail marketers/suppliers. The NERC Reliability Standards Development Procedure will be used to identify the changes necessary to terms and requirements in reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. Specifically, the following description has been incorporated into the scope for affected projects in this revised Reliability Standards Development Plan that includes a standard applicable to Load Serving Entities: Source: FERC's December 20, 2007 Order in Docket Nos. RC07-004-000, RC07-6-000, and RC07-7-000 Issue: In FERC's December 20, 2007 Order, the Commission reversed NERC's Compliance Registry decisions with respect to three load serving entities in the ReliabilityFirst (RFC) footprint. The distinguishing feature of these three LSEs is that none own physical assets. Both NERC and RFC assert that there will be a "reliability gap" if retail marketers are not registered as LSEs. To avoid a possible gap, a consistent, uniform approach to ensure that appropriate Reliability Standards and associated requirements are applied to retail marketers must be followed. Each drafting team responsible for reliability standards that are applicable to LSEs is to review and change as necessary, requirements in the reliability standards to address the issues surrounding accountability for loads served by retail marketers/suppliers. For additional information see: · FERC's December 20, 2007 Order (http://www.nerc.com/files/LSE_decision_order.pdf) · NERC's March 4, 2008 (http://www.nerc.com/files/FinalFiledLSE3408.pdf), · FERC's April 4, 2008 Order (http://www.nerc.com/files/AcceptLSECompFiling-040408.pdf), and · NERC's July 31, 2008 (http://www.nerc.com/files/FinalFiled-CompFiling-LSE-07312008.pdf) compliance filings to FERC on this subject.

Standard Review Form Project 2009-03 — Emergency Operations	
Standard #	**Title**
EOP-001-1	Emergency Operations Planning

Issues	FERC Order 693 Disposition: Approved with modification • Include reliability coordinators as an applicable entity. • Consider Southern California Edison's and Xcel's suggestions in the standard development process. • Clarify that the 30-minute requirement in requirement R2 to state that load shedding should be capable of being implemented as soon as possible but no more than 30 minutes. • Includes definitions of system states (e.g. normal, alert, emergency), criteria for entering into these states. And the authority that will declare them. • Consider a pilot program (field test) for the system states proposal. • Clarifies that the actual emergency plan elements, and not the "for consideration" elements of Attachment 1, should be the basis for compliance. V1 Industry Comments • Combine R4 & R5 • Revise R5 • Measures are really data retention requirements VRF comment • R1 – primarily administrative Other • Modify standard to conform with the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure.

Standard Review Form Project 2009-03 — Emergency Operations	
Standard #	**Title**
EOP-002-2	Capacity and Energy Emergencies
Issues	FERC Order 693 Disposition: Approved with modification • Address emergencies resulting not only from insufficient generation but also insufficient transmission capability, particularly as it affects the implement of the capacity and energy emergency plan. • Include all technically feasible resource options, including demand response and generation resources • Ensure the TLR procedure is not used to mitigate actual IROL violations.

	V0 Industry Comments • R3 should be applied to RC's • Re-wording in R7 • Measures aren't really measures but requirements • L4 non-compliance needs definition of time frame • Several wording changes to Attachment • Compliance not mapped to requirements VRF comments • ~~R10~~R9 - This is a commercial and administrative ordering of curtailments. Other • Modify standard to conform with the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure.

Standard Review Form Project 2009-03 — Emergency Operations	
Standard #	**Title**
EOP-003-1	Load Shedding Plans
Issues	FERC Order 693 Disposition: Approved with modification • Develop specific minimum load shedding capability that should be provided and the maximum amount of delay before load shedding can be implemented based on overarching nationwide criteria that take into account system characteristics. • Require periodic drills of simulated load shedding. • Suggest a review of industry best practices in determining nationwide criteria. • Consider comments from APPA and ISO-NE in the standards development process. V0 Industry Comments • Move implementation requirements • Re-state purpose • Move to Policy 5 & 9 • Add UVLS

	VRF comments • R4 – Needs clarification • R6 - Failure to shed load in this condition can inhibit restoration. Other • Modify standard to conform with the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure.

SAR for Project 2009-03 – Emergency Operations
Attachment 2

Global Improvements

The standard drafting team is expected to review the assigned standards and modify the standards to conform to the latest version of NERC's Reliability Standards Development Procedure, the NERC Standard Drafting Team Guidelines, and the ERO Rules of Procedure as described in this "Global Improvements" section.

Statutory Criteria

In accordance with Section 215 of the Federal Power Act, FERC may approve, by rule or order, a proposed reliability standard or modification to a reliability standard if it determines that "the standard is just, reasonable, not unduly discriminatory or preferential, and in the public interest."

The first three of these criteria can be addressed in large part by the diligent adherence to NERC's *Reliability Standards Development Procedure*, which has been certified by the ANSI as being open, inclusive, balanced, and fair. Users, owners, and operators of the bulk power system that must comply with the standards, as well as the end-users who benefit from a reliable supply of electricity and the public in general, gain some assurance that standards are just, reasonable, and not unduly discriminatory or preferential because the standards are developed through an ANSI-accredited procedure.

The remaining portion of the statutory test is whether the standard is "in the public interest." Implicit in the public-interest test is that a standard is technically sound and ensures a level of reliability that should be reasonably expected by end-users of electricity. Additionally, each standard must be clearly written, so that bulk power system users, owners, and operators are ~~put on notice~~informed of the expected behavior~~.~~ or have knowledge of the expected behavior~~.~~. Ultimately, the standards should be defensible in the event of a governmental authority review or court action that may result from enforcing the standard and applying a financial penalty.

The standards must collectively provide a comprehensive and complete set of technically sound requirements that establish an acceptable threshold of performance necessary to ensure the reliability of the bulk power system. "An adequate level of reliability" would argue for both a complete set of standards addressing all aspects of bulk power system design, planning, and operation that materially affect reliability, and for the technical efficacy of each standard. The Commission directed NERC to define the term, "adequate level of reliability" as part of its January 18, 2007 Order on Compliance Filing. Accordingly, NERC's Operating and Planning Committees prepared the definition and the NERC Board approved it at its February 2008 meeting for filing with regulatory authorities. The NERC Standards Committee was then tasked to integrate the definition into the development of future reliability standards.

Quality Objectives

To achieve the goals outlined above, NERC has developed 10 quality objectives for the development of reliability standards. Drafting teams working on assigned projects are charged to ensure their work adheres to the following quality objectives:

1. **Applicability —** Each reliability standard shall clearly identify the functional classes of entities responsible for complying with the reliability standard, with any specific additions or exceptions noted. Such functional classes[1] include: ERO, Regional Entities, reliability coordinators, balancing authorities, transmission operators, transmission owners, generator operators, generator owners, interchange authorities, transmission service providers, market operators, planning coordinators, transmission planners, resource planners, load-serving entities, purchasing-selling entities, and distribution providers. Each reliability standard that does not apply to the entire North American bulk power system shall also identify the geographic applicability of the standard, such as an interconnection, or within a regional entity area. The applicability section of the standard should also include any limitations on the applicability of the standard based on electric facility characteristics, such as a requirement that applies only to the subset of distribution providers that own or operate underfrequency load shedding systems.
2. **Purpose —** Each reliability standard shall have a clear statement of purpose that shall describe how the standard contributes to the reliability of the bulk power system.
3. **Performance Requirements —** Each reliability standard shall state one or more performance requirements, which if achieved by the applicable entities, will provide for a reliable bulk power system, consistent with good utility practices and the public interest. Each requirement is not a "lowest common denominator" compromise, but instead achieves an objective that is the best approach for bulk power system reliability, taking account of the costs and benefits of implementing the proposal.
4. **Measurability —** Each performance requirement shall be stated so as to be objectively measurable by a third party with knowledge or expertise in the area addressed by that requirement. Each performance requirement shall have one or more associated measures used to objectively evaluate compliance with the requirement. If performance results can be practically measured quantitatively, metrics shall be provided within the requirement to indicate satisfactory performance.

[1] These functional classes of entities are derived from NERC's Reliability Functional Model. When a standard identifies a class of entities to which it applies, that class must be defined in the Glossary of Terms Used in Reliability Standards.

5. **Technical Basis in Engineering and Operations —** Each reliability standard shall be based upon sound engineering and operating judgment, analysis, or experience, as determined by expert practitioners in that particular field.
6. **Completeness —** Each reliability standard shall be complete and self-contained. The standards shall not depend on external information to determine the required level of performance.
7. **Consequences for Noncompliance —** Each reliability standard shall make clearly known to the responsible entities the consequences of violating a standard, in combination with guidelines for penalties and sanctions, as well as other ERO and Regional Entity compliance documents.
8. **Clear Language —** Each reliability standard shall be stated using clear and unambiguous language. Responsible entities, using reasonable judgment and in keeping with good utility practices, are able to arrive at a consistent interpretation of the required performance.
9. **Practicality —** Each reliability standard shall establish requirements that can be practically implemented by the assigned responsible entities within the specified effective date and thereafter.
10. **Consistent Terminology —** Each reliability standard, to the extent possible, shall use a set of standard terms and definitions that are approved through the NERC Reliability Standards Development Process.

In addition to these factors, standard drafting teams also contemplate the following factors the Commission uses to approve a proposed reliability standard as outlined in Order No. 672. A standard proposed to be approved:

1. **Must be designed to achieve a specified reliability goal**
   "321. The proposed Reliability Standard must address a reliability concern that falls within the requirements of section 215 of the FPA. That is, it must provide for the reliable operation of bulk power system facilities. It may not extend beyond reliable operation of such facilities or apply to other facilities. Such facilities include all those necessary for operating an interconnected electric energy transmission network, or any portion of that network, including control systems. The proposed Reliability Standard may apply to any design of planned additions or modifications of such facilities that is necessary to provide for reliable operation. It may also apply to cyber security protection."

   "324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal.
   Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and

lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons."

2. **Must contain a technically sound method to achieve the goal**
   "324. The proposed Reliability Standard must be designed to achieve a specified reliability goal and must contain a technically sound means to achieve this goal.

   Although any person may propose a topic for a Reliability Standard to the ERO, in the ERO's process, the specific proposed Reliability Standard should be developed initially by persons within the electric power industry and community with a high level of technical expertise and be based on sound technical and engineering criteria. It should be based on actual data and lessons learned from past operating incidents, where appropriate. The process for ERO approval of a proposed Reliability Standard should be fair and open to all interested persons."

3. **Must be applicable to users, owners, and operators of the bulk power system, and not others**
   "322. The proposed Reliability Standard may impose a requirement on any user, owner, or operator of such facilities, but not on others."

4. **Must be clear and unambiguous as to what is required and who is required to comply**
   "325. The proposed Reliability Standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the Bulk-Power System must know what they are required to do to maintain reliability."

5. **Must include clear and understandable consequences and a range of penalties (monetary and/or non-monetary) for a violation**
   "326. The possible consequences, including range of possible penalties, for violating a proposed Reliability Standard should be clear and understandable by those who must comply."

6. **Must identify clear and objective criterion or measure for compliance, so that it can be enforced in a consistent and non-preferential manner**
   "327. There should be a clear criterion or measure of whether an entity is in compliance with a proposed Reliability Standard. It should contain or be accompanied by an objective measure of compliance so that it can be enforced and so that enforcement can be applied in a consistent and non-preferential manner."

7. **Should achieve a reliability goal effectively and efficiently - but does not necessarily have to reflect "best practices" without regard to implementation cost**
   "328. The proposed Reliability Standard does not necessarily have to reflect the optimal method, or "best practice," for achieving its reliability goal without regard to implementation cost or historical regional infrastructure design. It should however achieve its reliability goal effectively and efficiently."

8. **Cannot be "lowest common denominator," i.e., cannot reflect a compromise that does not adequately protect bulk power system reliability**
   "329. The proposed Reliability Standard must not simply reflect a compromise in the ERO's Reliability Standard development process based on the least effective North American practice — the so-called "lowest common denominator"—if such practice does not adequately protect Bulk-Power System reliability. Although the Commission will give due weight to the technical expertise of the ERO, we will not hesitate to remand a proposed Reliability Standard if we are convinced it is not adequate to protect reliability."

9. **Costs to be considered for smaller entities but not at consequence of less than excellence in operating system reliability**
   "330. A proposed Reliability Standard may take into account the size of the entity that must comply with the Reliability Standard and the cost to those entities of implementing the proposed Reliability Standard. However, the ERO should not propose a "lowest common denominator" Reliability Standard that would achieve less than excellence in operating system reliability solely to protect against reasonable expenses for supporting this vital national infrastructure. For example, a small owner or operator of the Bulk-Power System must bear the cost of complying with each Reliability Standard that applies to it."

10. **Must be designed to apply throughout North American to the maximum extent achievable with a single reliability standard while not favoring one area or approach**
    "331. A proposed Reliability Standard should be designed to apply throughout the interconnected North American Bulk-Power System, to the maximum extent this is achievable with a single Reliability Standard. The proposed Reliability Standard should not be based on a single geographic or regional model but should take into account geographic variations in grid characteristics, terrain, weather, and other such factors; it should also take into account regional variations in the organizational and corporate structures of transmission owners and operators, variations in generation fuel type and ownership patterns, and regional variations in market design if these affect the proposed Reliability Standard."

11. **No undue negative effect on competition or restriction of the grid**
    "332. As directed by section 215 of the FPA, the Commission itself will give special attention to the effect of a proposed Reliability Standard on competition. The ERO should attempt to develop a proposed Reliability Standard that has no undue

negative effect on competition. Among other possible considerations, a proposed Reliability Standard should not unreasonably restrict available transmission capability on the Bulk-Power System beyond any restriction necessary for reliability and should not limit use of the Bulk-Power System in an unduly preferential manner. It should not create an undue advantage for one competitor over another."

12. Implementation time
"333. In considering whether a proposed Reliability Standard is just and reasonable, the Commission will consider also the timetable for implementation of the new requirements, including how the proposal balances any urgency in the need to implement it against the reasonableness of the time allowed for those who must comply to develop the necessary procedures, software, facilities, staffing or other relevant capability."

13. Whether the reliability standard process was open and fair
"334. Further, in considering whether a proposed Reliability Standard meets the legal standard of review, we will entertain comments about whether the ERO implemented its Commission-approved Reliability Standard development process for the development of the particular proposed Reliability Standard in a proper manner, especially whether the process was open and fair. However, we caution that we will not be sympathetic to arguments by interested parties that choose, for whatever reason, not to participate in the ERO's Reliability Standard development process if it is conducted in good faith in accordance with the procedures approved by the Commission."

14. Balance with other vital public interests
"335. Finally, we understand that at times development of a proposed Reliability Standard may require that a particular reliability goal must be balanced against other vital public interests, such as environmental, social and other goals. We expect the ERO to explain any such balancing in its application for approval of a proposed Reliability Standard."

15. Any other relevant factors
"323. In considering whether a proposed Reliability Standard is just and reasonable, we will consider the following general factors, as well as other factors that are appropriate for the particular Reliability Standard proposed."

"337. In applying the legal standard to review of a proposed Reliability Standard, the Commission will consider the general factors above. The ERO should explain in its application for approval of a proposed Reliability Standard how well the proposal meets these factors and explain how the Reliability Standard balances conflicting factors, if any. The Commission may consider any other factors it deems appropriate for determining if the proposed Reliability Standard is just and reasonable, not unduly discriminatory or preferential, and in the public interest. The ERO applicant may, if it chooses, propose other such general factors in its ERO application and may propose additional specific factors for consideration with a particular proposed reliability standard."

Issues Related to the Applicability of a Standard

In Order No. 672, the Commission states that a proposed reliability standard should be clear and unambiguous regarding what is required and who is required to comply. Users, owners, and operators of the bulk power system must know what they are required to do to maintain reliability. Section 215(b) of the FPA requires all "users, owners and operators of the bulk power system" to comply with Commission-approved reliability standards.

The term "users, owners, and operators of the bulk power system" defines the statutory applicability of the reliability standards. NERC's Reliability Functional Model (Functional Model) further refines the set of users, owners, and operators by identifying categories of functions that entities perform so the applicability of each standard can be more clearly defined. Applicability is clear if a standard precisely states the applicability using the functions an entity performs. For example, "Each Generator Operator shall verify the reactive power output capability of each of its generating units" states clear applicability compared with a standard that states "a bulk power system user shall verify the reactive power output capability of each generating unit." The use of the Functional Model in the standards narrows the applicability of the standard to a particular class or classes of bulk power system users, owners, and operators. A standard is more clearly enforceable when it narrows the applicability to a specific class of entities than if the standard simply references a wide range of entities, e.g., all bulk power system users, owners, and operators.

In determining the applicability of each standard and the requirements within a standard, the drafting team should follow the definitions provided in the NERC Glossary of Terms Used in Reliability Standards and should also be guided by the Functional Model.

In addition to applying definitions from the Functional Model, the revised standards must address more specific applicability criteria that identify only those entities and facilities that are material to bulk power system reliability with regard to the particular standard.

The drafting team should review the registration criteria provided in the NERC Statement of Compliance Registry Criteria, which is the criteria for applicability. The registration criteria identify the criteria NERC uses to identify those entities responsible for compliance to the reliability standards. Any deviations from the criteria used in the Statement of Compliance Registry Criteria must be identified in the applicability section of the. It is also important to note that standard drafting teams cannot set the applicability of reliability standards to extend to entities beyond the scope established by the criteria for inclusion on NERC's Compliance Registry. This is expressly prohibited by Commission Order No. 693-A.

The goal is to place obligations on the entities whose performance will impact the reliability of the bulk power system, but to avoid painting the applicability with such a broad brush that entities are obligated even when meeting a requirement will make no material contribution to bulk power system reliability.

Every entity class described in the Functional Model performs functions that are essential to the reliability of the bulk power system. This point is best highlighted with the example that might be the most difficult to understand, the inclusion of distribution providers. Section 215 of the FPA specifically excludes facilities used in the local distribution of electric energy. Nonetheless, some of the NERC standards apply to a class of entities called Distribution Providers. Distribution Providers are covered because, although they own and operate facilities in the local distribution of electric energy, they also perform functions affecting and essential to the reliability of the bulk power system. With regard to these facilities and functions that are material to the reliability of the bulk power system, a distribution provider is a bulk power system user. For example, requirements for distribution providers in the reliability standards apply to the underfrequency load shedding relays that are maintained and operated within the distribution system to protect the reliability of the bulk power system. There are also requirements for distribution providers to provide demand forecast information for the planning of reliable operations of the bulk power system.

A similar line of thinking can apply to every other entity in the Functional Model, including Load-serving Entities and Purchasing-selling Entities, which are users of the bulk power system to the extent they transact business for the use of transmission service or to transfer power across the bulk power system. NERC has specific requirements for these entities based on how these uses may impact the reliability of the bulk power systems. Other functional entities are more obviously bulk power system owners and operators, such as Reliability Coordinators, Transmission Owners and Operators, Generator Owners and Operators, Planning Coordinators, Transmission Planners, and Resource Planners. It is the extent to which these entities provide for a reliable bulk power system or perform functions that materially affect the reliability of the bulk power system that these entities fall under the jurisdiction of Section 215 of the FPA and the reliability standards. The use of the Functional Model simply groups these entities into logical functional areas to enable the standards to more clearly define the applicability.

Issues Related to Regional Entities and Reliability Organizations

Because of the transition from voluntary reliability standards to mandatory reliability standards, confusion has occurred over the distinction between Regional Entities and Regional Reliability Organizations. The regional councils have traditionally been the owners and members of NERC. They have been referred to as Regional Reliability Organizations in the Functional Model and in the reliability standards. In an era of voluntary standards and guides, it was acceptable that a number of the standards included requirements for Regional Reliability Organizations to develop regional criteria, procedures, and plans, and included requirements for entities within the region to follow those requirements. Section 215 of the FPA introduced a new term, called “Regional Entity.”

Regional Entities have specific delegated authorities, under agreements with NERC, to propose and enforce reliability standards within the region, and to perform other functions in support of the electric reliability organization. The former Regional Reliability Organizations have entered into delegation agreements with NERC to become Regional Entities for this purpose.

With regard to distinguishing between the terms Regional Reliability Organizations and Regional Entities, the following guidance should be used. The corporations that provide regional reliability services on behalf of their members are Regional Reliability Organizations. NERC may delegate to these entities a set of regional entity functions. The Regional Reliability Organizations perform delegated regional entity functions much like NERC is the organization that performs the ERO function. Regional Reliability Organizations may do things other than their statutory or delegated regional entity functions.

With the regions having responsibility for enforcement, it is no longer appropriate for the regions to be named as responsible entities within the standards. The plan calls for removing requirements from the standards that refer to Regional Reliability Organizations, either by deleting the requirements or redirecting the responsibilities to the most applicable functions in the Functional Model, such as Planning Coordinators, Reliability Coordinators, or Resource Planners. In instances where a regional standard or criteria are needed, the ERO may direct the Regional Entities to propose a regional standard in accordance with ERO Rule 312.2, which states NERC, may “direct regional entities to develop regional reliability standards.” There is no need to have a NERC standard that directs the regions to develop a regional standard. NERC standards should only include requirements for Regional Entities in those rare instances where the regions have a specific operational, planning, or security responsibility. In this case, Regional Entities (or NERC) may be noted as the applicable entity. However, these Regional Entities (or NERC) are held accountable for compliance to these requirements through NERC’s Rules of Procedure that, by delegation agreement, extend to the Regional Entities. The Regional Entities are not users, owners, or operators of the bulk power system and cannot be held responsible for compliance through the compliance monitoring and enforcement program. However, NERC and the Regional Entities can be held by the Commission to be in violation of its rules of procedure for failing to comply with the standards requirements to which it is assigned.

Issues Related to Ambiguity

Drafting teams should strive to remove all potential ambiguities in the language of each standard, particularly in the performance requirements. Redundancies should also be eliminated.

Specifically, each performance requirement must be written to include four elements:

- **Who —** defines which functional entity or entities are responsible for the requirements, including any narrowing or qualifying limits on the applicability to or of an entity, based on material impact to reliability.

- **Shall do what —** describes an action the responsible entity must perform.
- **To what outcome** — describes the expected, measurable outcome from the action.
- **Under what conditions** — describes specific conditions under which the action must be performed. If blank, the action is assumed to be required at all times and under all conditions.

Each requirement should identify a product or activity that makes a definite contribution to reliability.

Drafting teams should focus on defining measurable outcomes for each requirement, and not on prescribing *how* a requirement is to be met. While being more prescriptive may provide a sense of being more measurable, it does not add reliability benefits and may be inefficient and restrict innovation.

Issues Related to Technical Adequacy

In May 2006, the Commission issued an assessment on the then proposed reliability standards. The Commission noted under a "technical adequacy" section that requirements specified in some standards may not be sufficient to ensure an adequate level of reliability. While Order No. 672 notes that "best practice" may be an inappropriately high standard, it also warns that a "lowest common denominator" approach will not be acceptable if it is not sufficient to ensure system reliability.

Each standard should clearly meet the statutory test of providing an adequate level of reliability to the bulk power system. Each requirement should be evaluated and the bar raised as needed, consistent with good practice and as supported by consensus.

Issues Related to Compliance Elements

Each reliability standard includes a section to address measures and a section to address compliance. The Uniform Compliance Monitoring and Enforcement Guidelines, ERO Sanctions Guidelines, and Compliance Registry Criteria have been modified and have been approved by the Commission. As each standard is revised, or as new standards are developed, drafting teams need to familiarize themselves with these documents to ensure that each standard proposed for ballot is in a format that includes all the elements needed to support reliability and to ensure that the standard can be enforced for compliance.

The compliance-related elements of standards that may need to be modified to meet the latest approved versions of the various compliance documents noted above include the following:

- Each requirement must have an associated Violation Risk Factor.

- Each requirement must have an associated Time Horizon.
- The term, "Compliance Monitor" has been replaced with the term, "Compliance Enforcement Authority." Either the Regional Entity or the ERO may serve as the compliance enforcement authority. For most standards, the Regional Entity will serve as the compliance enforcement authority. In the situation where a Regional Entity has authority over a reliability coordinator, for example, the ERO will serve as the compliance enforcement authority to eliminate any conflict of interest.
- The eight processes used to monitor and enforce compliance have been assigned new names.
    - Compliance Audits
    - Self-Certifications
    - Spot Checking
    - Compliance Violation Investigations
    - Self-Reporting
    - Periodic Data Submittals
    - Exception Reporting
    - Complaints
- The audit cycles for various entities have been standardized so that the Reliability Coordinator, Transmission Operator, and Balancing Authority will undergo a routine audit to assess compliance with each applicable requirement once every three years while all other responsible entities will undergo a routine audit once every six years.
- Levels of Non-compliance have been replaced with "Violation Severity Levels."

All requirements are subject to compliance audits, self-certification, spot checking, compliance violation investigations, self-reporting and complaints. Only a subset of requirements is subject to monitoring through periodic data submittals and exception reporting.

Measures: While a measure can be used for more than one requirement, there must be at least one measure for each requirement. A measure states what a responsible entity must have or do to demonstrate compliance to a third party, i.e., the compliance enforcement authority. Measures are "yardsticks" used to evaluate whether required performance or outcomes have been achieved. Measures do not add new requirements or expand the details of the requirements. Each measure shall be tangible, practical, and objective. A measure should be written so that achieving full compliance with the measure provides the compliance monitor with the necessary and sufficient information to demonstrate that the associated requirement was met by the responsible entity. Each measure should clearly refer to the requirement(s) to which it applies.

Violation Severity Levels: The Violation Severity Levels (formerly known as Levels of Non-Compliance) indicate how severely an entity violated a requirement. Historically, there has been confusion about Levels of Non-Compliance. Some of the previously existing Levels of Non-Compliance incorporate reliability-related risk impacts or consequences. Going forward, the risk or consequences component should be addressed only by the Violation Risk Factor, while the Violation Severity Levels should only be used to categorize how badly the requirement was violated.

Criteria for determining which VSL to use:
It is preferable to have four VSLs representing a spectrum of performance, but where that does not work; the VSLs should be defensible in supporting the criteria in the table below.

Lower VSL	Moderate VSL	High VSL	Severe VSL
The performance or product measured almost meets the full intent of the requirement.	The performance or product measured meets the majority of the intent of the requirement.	The performance or product measured does not meet the majority of the intent of the requirement, but does meet some of the intent.	The performance or product measured does not substantively meet the intent of the requirement.

Violation Risk Factors: Each drafting team is also instructed to develop a Violation Risk Factor for each requirement in a standard in accordance with the following definitions:

- **High Risk Requirement** — A requirement that, if violated, could directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures, or could place the bulk power system at an unacceptable risk of instability, separation, or cascading failures; or a requirement in a planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly cause or contribute to bulk power system instability, separation, or a cascading sequence of failures, or could place the bulk power system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.
- **Medium Risk Requirement** — A requirement that, if violated, could directly affect the electrical state or the capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. However, violation of a medium risk requirement is unlikely to lead to bulk electric system instability, separation, or cascading failures; or a requirement in a

planning time frame that, if violated, could, under emergency, abnormal, or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system. However, violation of a medium risk requirement is unlikely, under emergency, abnormal, or restoration conditions anticipated by the preparations, to lead to bulk power system instability, separation, or cascading failures, nor to hinder restoration to a normal condition.

- **Lower Risk Requirement —** A requirement that is administrative in nature and, a requirement that, if violated, would not be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor and control the bulk power system. A requirement that is administrative in nature; or a requirement in a planning time frame that, if violated, would not, under the emergency, abnormal, or restorative conditions anticipated by the preparations, be expected to affect the electrical state or capability of the bulk power system, or the ability to effectively monitor, control, or restore the bulk power system.

Time Horizons: The drafting team must also indicate the time horizon available for mitigating a violation to the requirement:

- **Long-term planning —** a planning horizon of one year or longer.
- **Operations planning —** operating and resource plans from day ahead up to and including seasonal.
- **Same-day operations —** routine actions required within the timeframe of a day, but not real time.
- **Real-time operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations assessment —** follow-up evaluations and reporting of real time operations.

Note that some requirements occur in multiple time horizons, and it is acceptable to have more than one time horizon for a single requirement.

The drafting team should seek input and review of all measures and compliance information from the compliance elements drafting team members assigned to support each standard drafting team or from the NERC compliance staff.

Coordination with NAESB

Many of the existing NERC standards are related to business practices, although their primary purpose is to support reliability. Reliability standards, business practices, and commercial interests are inextricably linked.

It would be safe to conclude that every reliability standard has some degree of commercial impact and therefore impacts competition. The statutory test to be applied by the Commission is whether the reliability standard has an “undue adverse effect” on competition.

NERC has taken several steps to ensure its reliability standards do not have any undue, adverse impact on business practices or competition. First, NERC coordinates the development of all standards with the North American Energy Standards Board (NAESB). In addition to this formal process, drafting teams work with NAESB groups to ensure effective coordination of wholesale electric business practice standards and reliability standards. NERC and NAESB follow their procedure for the joint development of standards in areas that have both reliability and business practice elements. This procedure is being implemented for all standards in which the reliability and business practice elements are closely related, thereby making joint development a more efficient approach.

This project will require close coordination and joint development with NAESB as there are anticipated revisions to these standards that may need new or revised associated business practices.

To ensure each reliability standard does not have an undue adverse effect on competition, NERC requires that each standard meet the following criteria:

- Competition — A reliability standard shall not give any market participant an unfair competitive advantage.
- Market Structures — A reliability standard shall neither mandate nor prohibit any specific market structure.
- Market Solutions — A reliability standard shall not preclude market solutions to achieve compliance with that standard.
- Commercially Sensitive Information — A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.

During the standards development process, each Standards Authorization Request (SAR) drafting team asks the following question to determine if there is a need to develop a business practice associated with the proposed standard:

- Are you aware of any associated business practices that we should consider with this SAR?

Each standard drafting team also asks the following question to determine if there is a potential conflict between a reliability standard and business practice:

- Are you aware of any conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement, or agreement? If yes, please identify the conflict.

Additional Considerations

Drafting teams should consider the following in reviewing and revising their assigned standards:

- **Title**: In general, the title should be concise and to the point. Care should be taken not to try to fully describe a standard through its title. The title should fit a single line in both the header and in the body of the standard.
- **Purpose**: The purpose should clearly state a benefit to the industry (value proposition) in fulfilling the requirements. The purpose should not simply state "the purpose is to develop a standard to…" The purpose should be tied to one or more of the reliability principles.
- **References**: Section (F) provides a place to list associated references that support implementation of the standard. Drafting teams may develop or reference supporting documents with approval of the Standards Committee.
- **Version histories**: Version histories should be expanded to include complete listings of what has been changed from version to version so that end-users can easily keep track of changes to standards. This will also serve as a type of audit trail for changes.

Resource Documents Used

NERC used several references when preparing this plan. These references provide detailed descriptions of the issues and comments that need to be considered by the drafting teams, which are included in the second volume of the work plan, as they work on the standards projects defined in the plan. The references include:

- FERC NOPR on Reliability Standards, October 20, 2006.
- FERC Staff Preliminary Assessment of Proposed Reliability Standards, May 11, 2006.
- FERC Order No. 693 Mandatory Reliability standards for the Bulk Power System, March 16, 2007.
- FERC Order No. 693-A Mandatory Reliability Standards for the Bulk Power System, July 19, 2007.
- FERC Order No. 890 Preventing Undue Discrimination and Preference in Transmission Service, February 16, 2007.
- Comments of the North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment of Reliability Standards, June 26, 2006.

- Comments of the North American Electric Reliability Corporation on Staff Preliminary Assessment of NERC Standards CIP-002 through CIP-009, February 12, 2007.
- Comments of the North American Electric Reliability Corporation on the Notice of Proposed Rulemaking for Facilities Design, Connections and Maintenance Reliability standards, September 19, 2007.
- Comments received during the development of Version 0 reliability standards.
- Consideration of comments of the Missing Compliance Elements drafting team.
- Consideration of comments of the Violation Risk Factors drafting team.
- Consideration of comments in the Phase III–IV standards.
- Comments received during industry comment period on work plan.
- Q&A for Standards and Compliance.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Five-Year Review Template

Updated July 29, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-001-2.1b Emergency Operations Planning
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111, ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: July 11, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

☒ Yes

☐ No

Please summarize your application of Paragraph 81 Criteria, if any:

Requirement R3:

- Requirement R3.1 should be covered by EOP-001-2.1b Requirement R4 in Attachment 1 (notifications that should be included in the plan are identified). COM-001 and COM-002 are descriptive in the identification of protocols to use and, thus, cover the generic reference. With the recommended revision to Attachment 1 of EOP-001-2.1b along with COM-001 and COM-002 generic reference, Requirement R3.1 would meet Criterion B7 as redundant, as well as Criterion A (R3.1 does little, if anything, to benefit or protect the reliable operation of the BES) of Paragraph 81 and should be retired
- Requirement R3.2 should be covered by EOP-001-2.1b Requirement R4 in Attachment 1 which lists the actions to take during capacity situations specified in the plan. Load reduction within timelines is covered in BAL-002 Requirement R2. With the recommended revision of EOP-001 Requirement R4, Requirement R3.2 would meet Criterion B7 as redundant, as well as Criterion A (R3.1 does little, if anything, to benefit or protect the reliable operation of the BES) of Paragraph 81 and should be retired
- Requirement R3.4 meets Paragraph 81 Criterion B1; staffing levels are administrative in nature and would result in an increase in efficiency in the ERO compliance program (it is a simple check off during an audit). Requirement R3.4 also meets with Criterion A of Paragraph 81, as a check off does not enhance the reliability of the BES. Requirement R3.4 should be retired as falling under Criterion B1 and Criterion A of Paragraph 81

Requirement 6:

- Requirement R6.1 is redundant with COM-001, meeting Criterion B7 as redundant under Paragraph 81 and should be retired
- Requirement R6.2 speaks to an action to be taken during capacity issues that is not feasible in accomplishing. Transaction arrangements are also a commercial practice; and, thus, Requirement R6.2 meets Criterion B6 of Paragraph 81 and should be retired
- Requirement R6.3 is redundant with EOP-001-2b Requirement R4 and Attachment 1; whereby meeting Criterion B7 as redundant under Paragraph 81 and should be retired
- Requirement R6.4 does not provide for benefit for reliability of the BES, meeting Criterion A of Paragraph 81 and should be retired

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

   Please summarize your assessment:
   The EOP FYRT recommends that EOP-001-2.b and EOP-002-3.1 to be revised and merged into one standard identifying clearly and separately the Transmission Operator, Generation Operator and Reliability Coordinator issues as they relate to the BA and TOP (to address Paragraph 548 of Order 693) and how it needs to be planned and implemented for on the BES by the specific functional entities.
   - Requirement R1 needs clarity provided as to what an operating agreement constitutes and adjust the VSL to reflect current interpretations with the number of agreements needed. Requirement R1 must also account for current interpretations found in the Appendix and other interpretations.
   - Requirement R2 needs clarity provided, as instructed by the Commission, on the ambiguity of the EOP standards as it relates to the responsibilities of the Transmission Operator and Balancing Authority.
   - Requirement R5, the need to share emergency plans with neighboring Transmission Operators and Balancing Authorities should be removed as an administrative burden (identified in P81); however, the remaining language of the requirement should be affirmed
   - Review is recommended for Attachment 1 as it relates to the GOP in light of recent BES events (Cold Weather Event)

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

   ☒ Yes

   ☐ No

Please explain:
Appendix 1, question 3 attempts to define what a remote Balancing Authority is through an interpretation. This clarification should be addressed in a future revision of the Standard.

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

   Additional measures must be provided with this standard. There are no performance measures. FERC-approved VRFs should be incorporated within this standard. Requirement R1, once recommended clarity is provided as to what an operating agreement constitutes, adjustment to the VSL will be necessary to reflect current interpretations with the number of agreements needed.

   ☐ Yes

   ☒ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

   ☐ Yes

   ☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☐ Yes

   ☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

☒ Yes
☐ No

Guiding Questions:

If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE – Requirement R1, R2, R3, R5, R6 and Attachment 1

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*: See responses to questions 1, 2 and 4 above.

Preliminary Recommendation posted for industry comment (date):

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☐ REVISE

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Five-Year Review Template

Updated July 29, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-002-3.1 Capacity and Energy Emergencies
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111,ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: July 11, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered “Yes” to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   - Requirement R1 is redundant with IRO-001 and PER-001-2 and should be retired under Criterion B7 of Paragraph 81
   - Requirement R6 is redundant with BAL-002-1a and should be retired under Criterion B7 of Paragraph 81
   - Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request; informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 as a whole. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

   Please summarize your assessment:

The EOP FYRT recommends that EOP-001-2b and EOP-002-3.1 be revised and merged into one standard to address redundancy in the stating that a plan should be implemented. Both standards are different enough that those requirements not identified in retirement recommendations under Paragraph 81 should be retained.
Requirement R8 and Attachment 1 have several issues regarding applicability to different functions and should be revised to eliminate discrepancies and to form consistency.
Attachment 1 needs to be reviewed for consistency with IRO and TOP standards. The EOP FYRT recommends review of the uniqueness as it relates to ERCOT and similarly situated BAs.
Address the directive in Paragraph 573 of Order 693.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes

☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

☒ Yes

☐ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

☐ Yes

☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to

reliability if the Reliability Standard is not revised: Requirement R9 (recommended for retirement under Paragraph 81) the TSP now has the ability to change the Transmission priority, which is in turn reflected in the IDC.

☒ Yes

☐ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

☒ Yes
☐ No

Guiding Questions:

If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE (and merge with EOP-001-2b)

☒ RETIRE – Requirements R1, R6 and R9 in its entirety

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment (date):

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☐ REVISE

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

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8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant

The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)

Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?

The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?

The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?

The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Five-Year Review Template

Updated July 29, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-003-2 Load Shedding Plans
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111, ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: July 11, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered “Yes” to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   - Requirements R5 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R5 speaks to shedding loads in steps, that same process will be done in Requirement R1. Requirement R5 should be retired under Criterion B7 of Paragraph 81
   - Requirements R6 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R6 speaks of two events that must be valid to tell the BA or TOP to shed more load, but overall the action of shedding load to meet insufficient generation is the same as stated in Requirement R1. Requirement R6 should be retired under Criterion B7 of Paragraph 81
   - EOP-003-2– Recommend that Requirements R2, R4 and R7 be moved to PRC-010-0 or otherwise addressed during Project 2008-02 – Undervoltage Load Shedding.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

   Please summarize your assessment:

The EOP 5YR team believes that Requirements R2, R4 and R7 should be coordinated with the revision of PRC-010 (Project 2008-02 Undervoltage Load Shedding) for inclusion in that standard. This is consistent with the review that was done for automatic underfrequency requirements and should also be performed for automatic undervoltage requirements.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

   ☐ Yes

   ☒ No

   Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

   The Measures and Data retention should be reviewed and updated.

   ☐ Yes

   ☒ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

   ☐ Yes

   ☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☐ Yes

   ☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE – Retire Requirements R5, R6, R2, R4 and R7 and address directives in Paragraphs 595 and 603 of Order 693

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*: See responses to questions 1, 2, and 4 above.

Preliminary Recommendation posted for industry comment (date):

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☐ REVISE

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant

The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)

Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?

The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?

The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?

The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Directive Summary	Document Reference	Publication Date	Reference	Standard	Full Text
S- Ref 10063 - We direct the ERO to determine the optimum number of continent-wide system states and their attributes and to modify the Reliability Standards through the Reliability Standards development process to accomplish this objective.	Order 693	16-Mar-07	Para 561	EOP-001	561. As we noted in the NOPR, some control areas define and effectively use more than the "normal," "alert" and "emergency" system states included in the Blackout Report recommendation. We proposed that the ERO determine the optimum number of system states to be employed continent-wide and to consider the addition of the restoration state. Accordingly, we direct the ERO to determine the optimum number of continent-wide system states and their attributes and to modify the Reliability Standard through the Reliability Standards development process to accomplish this objective.
S- Ref 10064 - Consider a pilot program (field test) for the system states proposal.	Order 693	16-Mar-07	Para 562	EOP-001	562. Further, we agree with ISO-NE that the proposed modification should be field tested and that policies and procedure be put in place, including operator training, before any processes for continent-wide system states are implemented. Such testing will help assure that all applicable entities and their personnel understand how the terms will be used and will allow operators to train staff to make any necessary changes to their policies and procedures. We direct the ERO to consider such a pilot program as it modifies EOP-001-0 through the Reliability Standards development process.
S- Ref 10065 - Clarifies that the actual emergency plan elements, and not the for consideration elements of Attachment 1, should be the basis for compliance.	Order 693	16-Mar-07	Para 565	EOP-001	565. The Commission agrees with ISO-NE that the Reliability Standard should be clarified to indicate that the actual emergency plan elements, and not the "for consideration" elements of Attachment 1, should be the basis for compliance. However, all of the elements should be considered when the emergency plan is put together.
S- Ref 10066 - Address emergencies resulting not only from insufficient generation but also insufficient transmission capability, particularly as it affects the implement of the capacity and energy emergency plan.	Order 693	16-Mar-07	Para 571	EOP-002	571. As we stated in the NOPR, neither EOP-002-2 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies. The Commission agrees with MRO that "insufficient transmission capability" could be due to various causes. The ERO should examine whether to clarify this term in the Reliability Standards development process.
S- Ref 10067 - Include all technically feasible resource options, including demand response and generation resources	Order 693	16-Mar-07	Para 573	EOP-002	573. The Commission agrees with FirstEnergy that for demand-side resources to qualify as another tool for balancing authorities to use in meeting control performance and disturbance control Reliabilty Standards, they must meet comparable technical performance requirements as generation resource options. In response to comments from Comverge and APPA, the Commission believes that curtailable loads are adequately addressed in Requirement R6 of the Reliability Standard but that demand response is not covered. Demand response covers considerably more resources than interruptible load. Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements.
S- Ref 10072 - Develop specific minimum load shedding capability that should be provided .. based on overarching nationwide criteria that take into account system characteristics.	Order 693	16-Mar-07	Para 595	EOP-003	595. The Commission concludes that the Reliability Standard needs to be modified to ensure that adequate load shedding capabilities are provided so that system operators have an effective operating measure of last resort to contain system emergencies and prevent cascading. The Commission recognizes that the amount of load shedding capability required is dependent on system characteristics and therefore it may not be feasible to have a uniform nationwide load shedding capability. This, however, does not preclude a uniform nationwide criterion on the methodology for establishing load shedding capability that would specify the minimum amount of load shedding capability that should be provided based on system characteristics and conditions and the maximum amount of delay before load shedding can be implemented. The Commission directs the ERO to address the minimum load and maximum time concerns of the Commission through the Reliability Standards development process. We suggest that a review of industry best practices would be useful in developing nationwide critera.

S- Ref 10073 - Require periodic drills of simulated load shedding.	Order 693	16-Mar-07	Para 597	EOP-003	597. As suggested by California PUC, periodic drills of simulated load shedding should involve all participants required to ensure successful implementation of load shedding plans. As such, the drills should extend beyond system operators to distribution operators and LSEs. The Reliability Standard should require periodic drills by entities subject to section 215, and require those entities to seek participation by other entities. The drills should test the readiness and functionality of the load shedding plans, including, at times, the actual deployment of personnel. Therefore the Commission disagrees with FirstEnergy that the requirement for periodic drills of simulated load shedding should be incorporated into the new PER-005-0 Reliability Standard that is currently being drafted to address operator training.
S- Ref 10074 - Consider comments from APPA in the standards development process.	Order 693	16-Mar-07	Para 601	EOP-003	
548. Further we agree with SoCal Edison that clear direction is needed on which requirements should be exclusive to transmission operators and balancing authorities with the reliability coordinator being responsible for incorporating this information into its overarching plan. Accordingly, the Commission finds the reliability coordinator is a necessary entity under EOP-001-0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity. In addition, the ERO should consider SoCal Edison's suggestion in the ERO's Reliability Standards development process.	Order 693	16-Mar-07	Para 548	EOP-001	548. Further we agree with SoCal Edison that clear direction is needed on which requirements should be exclusive to transmission operators and balancing authorities with the reliability coordinator being responsible for incorporating this information into its overarching plan. Accordingly, the Commission finds the reliability coordinator is a necessary entity under EOP-001-0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity. In addition, the ERO should consider SoCal Edison's suggestion in the ERO's Reliability Standards development process.

FYRT Notes

NOTE: The FYRT suggested revisions to Attachment 1 that may address this directive.

NOTE: This language is no longer in the standard.

NOTE: See Para 572 for more specific recommendations.

NOTE: May want to perfrorm a data request to see what ndustry is doing today and attempt to develop a "floor". See also Para 603.

NOTE: See para 603 also.

APPA Comments are in Paragraph 598: "In addition, APPA states that NERC should consider requiring balancing authorities and transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners."

Associated Standard	Associated Project	Source
EOP-001	2009-03	Version 1 Team
EOP-001	2009-03	Version 1 Team
EOP-001	2009-03	Version 1 Team
EOP-001	2009-03	VRFs Team
EOP-003	2009-03	Version 0 Team
EOP-003	2009-03	Version 0 Team
EOP-003	2009-03	Version 0 Team
EOP-003	2009-03	VRFs Team
EOP-003	2009-03	VRFs Team
EOP-001	2009-03	NERC Audit Observation Team
EOP-002	2009-03	NERC Audit Observation Team
EOP-003	2009-03	NERC Audit Observation Team
EOP-001	2009-03	Real-time Best Practices Standards Study Group
EOP-003	2009-03	Real-time Best Practices Standards Study Group

EOP-001	2009-03	Frank Gaffney (FMPA)
EOP-001	2009-03	Frank Gaffney (FMPA)
EOP-001	2009-03	Frank Gaffney (FMPA)
EOP-001	2009-03	Frank Gaffney (FMPA)

EOP-001	2009-03	Frank Gaffney (FMPA)

Issue Description
Combine R4 & R5
Revise R5
Measures are really data retention requirements
R1 primarily administrative
Move implementation requirements
Re-state purpose
Add UVLS
R4 Needs clarification
R6 - Failure to shed load in this condition can inhibit restoration.
BA shall have operating agreements with adjacent BA's that shall, at a minimum, contain provisions for emeergency assistance, including provision to obtain emergency assistanc from remote BA's. What is "emergency assistance"? Does a reserve sharing grou
This NERC standard references the RC or BA to implement it's capacity and energy plans. The RC does not have capacity and energy plans.
The purpose of the standard states that the BA and TOP must have the capability and authority to shed load. What do we mean by capability? Is directing someone to take action to open breakers the same thing as capability?
Establish document plans and procedures for conservative operations
Provide the location, Real-time status, and MWs of Load available to be shed.

The NERC Glossary of terms defines a BA as: "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." In oth
The NERC Glossary of terms defines a TOP as: "(t)he entity responsible for the reliability of its 'local' transmission system, and that operates or directs the operations of the transmission facilities." With this definition in mind, why is the TOP made r
Requirement R4 (and by reference Attachment 1-EOP-001-0) is applicable to both the Transmission Operator and Balancing Authority but includes items that are not applicable to the TOP and are only applicable to the BA, e.g., why is a TOP responsible for fu
With regard to requirement R2, why is the BA responsible for Under Frequency Load Shedding (UFLS) when PRC-006-0 and PRC-007-0 make it the responsibility of the Regional Entities, the TOPs, the Distribution Providers and the LSEs? Why is the BA responsibl

Requirement R2 of EOP-003-1 states: Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions. The standards drafting team for Project 2007-01 Underfequency Load She

Paragraph 81 Criteria

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

B2. Data Collection/Data Retention

These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant

The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)

Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?

The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?

The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?

The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Unofficial Comment Form

Project 2009-03 Emergency Operations

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the draft Five-Year Review Recommendation on the EOP body of standards. A group of Five-Year Review templates that shows the scope of the recommended changes is also posted for information. The electronic comment form must be completed by 8:00 p.m. ET **September 19, 2013**.

If you have questions please contact Laura Anderson (via email) or by telephone at (404) 446-9671.

Project 2009-03 Emergency Operations Five-Year Review Project Page

Background Information

The Standards Committee assigned eight subject matter experts to review the EOP standards as part of NERC's obligation to conduct periodic reviews of its standards. The Five-Year Review Team recommends certain revisions to the EOP standards to provide greater clarity and to sharpen industry focus on tasks that have a more direct impact on reliability. As required by the NERC Standard Processes Manual, this recommendation is being posted for stakeholder comment prior to being finalized and submitted to the Standards Committee.

EOP-001-2.1b: The EOP FYRT recommends retiring Requirements R3.1, R6.1 and R6.3 under Criterion B7 of Paragraph 81; Requirement R3.2 under Criterion B7 and Criterion A of Paragraph 81; Requirement R3.4 under Criterion B1 and Criterion A of Paragraph 81; Requirement R6.2 under Criterion B6 of Paragraph 81; and Requirement R6.4 under Criterion A of Paragraph 81.

The EOP FYRT further recommends revising and merging EOP-001-2.b and EOP-002-3.1 into one standard; revising Requirements R1, R2 and R5; and a review of Attachment 1.

EOP-002-3.1: The EOP FYRT recommends retiring Requirements R1 and R6 under Criterion B7 of Paragraph 81; and Requirement R9 under Criterion A of Paragraph 81.

The EOP FYRT further recommends that EOP-001-2b and EOP-002-3.1 be revised and merged into one standard and revisions are recommended for Requirement R8 and Attachment 1.

EOP-003-2: The EOP FYRT recommends retiring Requirements R5 and R6 under Criterion B7 of Paragraph 81. Requirements R2, R4 and R7 are recommended to be moved to PRC-010-0.

Questions

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

1. Do you agree with the recommendation regarding EOP-001-2.1b? If not, please explain specifically what aspects of the recommendation you disagree with.

☐ Yes
☐ No
Comments:

2. Do you agree with the recommendation regarding EOP-002-3.1? If not, please explain specifically what aspects of the recommendation you disagree with.

☐ Yes
☐ No
Comments:

3. Do you agree with the recommendation regarding EOP-003-2? If not, please explain specifically what aspects of the recommendation you disagree with.

☐ Yes
☐ No
Comments:

4. If you have any other comments on the EOP Five-Year Review Recommendations that you have not already mentioned above, please provide them here:
Comments:

A. Introduction

1. **Title:** **Emergency Operations Planning**

2. **Number:** EOP-001-2.1b

3. **Purpose:** Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. **Applicability**

   4.1. Balancing Authorities.

   4.2. Transmission Operators.

5. **Proposed Effective Date:** Twenty-four months after the first day of the first calendar quarter following applicable regulatory approval. In those jurisdictions where no regulatory approval is required, all requirements go into effect twenty-four months after Board of Trustees adoption.

B. Requirements

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.

R2. Each Transmission Operator and Balancing Authority shall:

R2.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

R2.3. Develop, maintain, and implement a set of plans for load shedding.

R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include:

R3.1. Communications protocols to be used during emergencies.

R3.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.

R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

R3.4. Staffing levels for the emergency.

R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan.

R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.

R6. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable:

R6.1. The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.

R6.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.

R6.3. The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)

R6.4. The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.

C. Measures

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

The Regional Reliability Organization shall review and evaluate emergency plans every three years to ensure that the plans consider the applicable elements of Attachment 1-EOP-001.

The Regional Reliability Organization may elect to request self-certification of the Transmission Operator and Balancing Authority in years that the full review is not done.

Reset: one calendar year.

1.3. Data Retention

Current plan available at all times.

1.4. Additional Compliance Information

Not specified.

2. Violation Severity Levels:

Requirement	Lower	Moderate	High	Severe
R1	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for less than 25% of the adjacent BAs. Or less than 25% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 25% to 50% of the adjacent BAs. Or 25 to 50% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 50% to 75% of the adjacent BAs. Or 50% to 75% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 75% or more of the adjacent BAs. Or more than 75% of those agreements do not contain provisions for emergency assistance.
R2	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	N/A	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.
R2.1	The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of emergency plans to mitigate insufficient generating capacity emergency plans but the plans are not maintained.	The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity emergency plans are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop emergency mitigation plans for insufficient generating capacity.
R2.2	The Transmission Operator or Balancing Authority's plans to mitigate transmission system emergencies are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of transmission system emergency plans but are not maintained.	The Transmission Operator or Balancing Authority's transmission system emergency plans are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement operating emergency mitigation plans for emergencies on the transmission system.

Requirement	Lower	Moderate	High	Severe
R2.3	The Transmission Operator or Balancing Authority’s load shedding plans are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of load shedding plans but are not maintained.	The Transmission Operator or Balancing Authority's load shedding plans are partially compliant with the requirement but are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement load shedding plans.
R3	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with all four (4) of the sub-components.
R3.1	The Transmission Operator or Balancing Authority’s communication protocols included in the emergency plan are missing minor program/procedural elements.	N/A	N/A	The Transmission Operator or Balancing Authority has failed to include communication protocols in its emergency plans to mitigate operating emergencies.
R3.2	The Transmission Operator or Balancing Authority’s list of controlling actions has resulted in meeting the intent of the requirement but is missing minor program/procedural elements.	N/A	The Transmission Operator or Balancing Authority provided a list of controlling actions, however the actions fail to resolve the emergency within NERC-established timelines.	The Transmission Operator or Balancing Authority has failed to provide a list of controlling actions to resolve the emergency.

Requirement	Lower	Moderate	High	Severe
R3.3	The Transmission Operator or Balancing Authority has demonstrated coordination with Transmission Operators and Balancing Authorities but is missing minor program/procedural elements.	N/A	N/A	The Transmission Operator or Balancing Authority has failed to demonstrate the tasks to be coordinated with adjacent Transmission Operator and Balancing Authorities as directed by the requirement.
R3.4	The Transmission Operator or Balancing Authority's emergency plan does not include staffing levels for the emergency	N/A	N/A	N/A
R4	The Transmission Operator and Balancing Authority's emergency plan has complied with 90% or more of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with 70% to 90% of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with between 50% to 70% of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with 50% or less of the number of sub-components
R5	The Transmission Operator and Balancing Authority is missing minor program/procedural elements.	The Transmission Operator and Balancing Authority has failed to annually review one of it's emergency plans	The Transmission Operator and Balancing Authority has failed to annually review two of its emergency plans or communicate with one of it's neighboring Balancing Authorities.	The Transmission Operator and Balancing Authority has failed to annually review and/or communicate any emergency plans with its Reliability Coordinator, neighboring Transmission Operators or Balancing Authorities.
R6	The Transmission Operator and/or the Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator and/or the Balancing Authority failed to comply with two (2) of the sub-components.	The Transmission Operator and/or the Balancing Authority has failed to comply with three (3) of the sub-components.	The Transmission Operator and/or the Balancing Authority has failed to comply with four (4) or more of the sub-components.

Requirement	Lower	Moderate	High	Severe
R6.1	The Transmission Operator or Balancing Authority has failed to establish and maintain reliable communication between interconnected systems.	N/A	N/A	N/A
R6.2	The Transmission Operator or Balancing Authority has failed to arrange new interchange agreements to provide for emergency capacity or energy transfers with required entities when existing agreements could not be used.	N/A	N/A	N/A
R6.3	The Transmission Operator or Balancing Authority has failed to coordinate transmission and generator maintenance schedules to maximize capacity or conserve fuel in short supply.	N/A	N/A	N/A
R6.4	The Transmission Operator or Balancing Authority has failed to arrange for deliveries of electrical energy or fuel from remote systems through normal operating channels.	N/A	N/A	N/A

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	October 17, 2008	Deleted R2 Replaced Levels of Non-compliance with the February 28, 2008 BOT approved Violation Severity Levels Corrected typographical errors in BOT approved version of VSLs	Revised IROL Project
2	August 5, 2009	Removed R2.4 as redundant with EOP-005-2 Requirement R1 for the Transmission Operator; the Balancing Authority does not need a restoration plan.	Revised Project 2006-03
2	August 5, 2009	Adopted by NERC Board of Trustees: August 5, 2009	Revised
2	March 17, 2011	FERC Order issued approving EOP-001-2 (Clarification issued on July 13, 2011)	Revised
2b	November 4, 2010	Adopted by NERC Board of Trustees	Project 2008-09 - Interpretation of Requirement R1
2b	November 4, 2010	Adopted by NERC Board of Trustees	Project 2009-28 - Interpretation of Requirement R2.2
2b	December 15, 2011	FERC Order issued approving Interpretation of R1 and R2.2 (Order effective December 15, 2011)	Project 2008-09 - Interpretation of Requirement R1 and Project 2009-28 - Interpretation of Requirement R2.2
2.1b	March 8, 2012	Errata adopted by Standards Committee; (changed title and references to Attachment 1 to omit inclusion of version numbers and corrected references in Appendix 1 Question 4 from "EOP-001-0" to "EOP-001-2")	Errata

2.1b	September 13, 2012	FERC approved	Errata

Attachment 1-EOP-001

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system's own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

Appendix 1

Requirement Number and Text of Requirement
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
Questions:
1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition? 2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance? 3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement? 4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-2, Requirement 1?
Responses:
1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe the conditions under which the emergency energy will be delivered to the responsible Balancing Authority. 2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections. 3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities. 4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-2.

Appendix 2

Requirement Number and Text of Requirement
R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Questions:
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Questions:
The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001."

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard EOP-001-2.1b — Emergency Operations Planning

United States

Standard	Requirement	Enforcement Date	Inactive Date
EOP-001-2.1b	All	07/01/2013	

A. Introduction

1. **Title**: **Capacity and Energy Emergencies**
2. **Number**: EOP-002-3.1
3. **Purpose**: To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.
4. **Applicability**
   - **4.1.** Balancing Authorities.
   - **4.2.** Reliability Coordinators.
   - **4.3.** Load-Serving Entities.
5. **(Proposed) Effective Date:** First day of the first calendar quarter six months following applicable regulatory approval; or, in those jurisdictions where no regulatory approval is required, the first day of the first calendar quarter six months following Board of Trustees adoption.

B. Requirements

R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.

R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan to reduce risks to the interconnected system.

R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.

R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

- **R6.1.** Loading all available generating capacity.
- **R6.2.** Deploying all available operating reserve.
- **R6.3.** Interrupting interruptible load and exports.
- **R6.4.** Requesting emergency assistance from other Balancing Authorities.
- **R6.5.** Declaring an Energy Emergency through its Reliability Coordinator; and

R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:

R7.1. Manually shed firm load without delay to return its ACE to zero; and

R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."

R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.

R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff:

R9.1. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."

R9.2. The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.

R9.3. The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

R9.4. The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

C. Measures

M1. Each Reliability Coordinator and Balancing Authority shall have and provide upon request evidence that could include but is not limited to, job descriptions, signed agreements, authority letter signed by an appropriate officer of the company, or other equivalent evidence that will be used to confirm that it meets Requirement 1.

M2. If a Reliability Coordinator or Balancing Authority implements one or more actions described in its Capacity and Energy Emergency plan, that entity shall have and provide upon request evidence that could include but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, computer printouts or other equivalent evidence that will be used to determine if the actions it took to relieve emergency conditions were in conformance with its Capacity and Energy Emergency Plan. (Requirement 2)

M3. If a Balancing Authority experiences an operating Capacity or Energy Emergency it shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if it met Requirement 3.

M4. The Balancing Authority shall have and provide upon request evidence (such as operator logs, work orders, E-Tags, or other evidence) that it took the actions described in R4 in response to anticipating a capacity or energy emergency.

M5. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it only used the assistance provided by the Interconnection frequency bias for the time needed to implement corrective actions and did not attempt to return Interconnection frequency to normal through unilateral adjustment of generation beyond that supplied through the frequency bias action and Interchange Schedule changes. (Requirement 5)

M6. The Balancing Authority shall have and provide upon request evidence (such as operator logs, dispatch instructions, or other evidence) that it took actions such as those listed in R6 to comply with CPS and DCS.

M7. The Balancing Authority shall have and provide upon request evidence (such as operator logs, voice recordings, or other evidence) that it took the actions listed in R7 when unable to resolve an emergency condition.

M8. If a Reliability Coordinator has any Balancing Authority within its Reliability Coordinator Area that has notified the Reliability Coordinator of a potential or actual Energy Emergency, the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence to determine if it initiated an Energy Emergency Alert as specified in Requirement 8 and as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts."

M9. If a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources), the Reliability Coordinator involved in the event shall have and provide upon request evidence that could include, but is not limited to, NERC reports, EEA reports, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or other equivalent evidence that will be used to determine if that Reliability Coordinator met Requirements 9.2, 9.3 and 9.4.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Compliance Monitoring Period and Reset Timeframe

Not Applicable.

1.3. Compliance Monitoring and Enforcement Process

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints

1.4. Data Retention

For Measure 1, each Reliability Coordinator and Balancing Authority shall keep The current in-force documents.

For Measure 2, 8 and 9 the Reliability Coordinator shall keep 90 days of historical data.

For Measure 3, 4, 5, 6, and 7 the Balancing Authority shall keep 90 days of historical data.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information

None.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	September 19, 2006	Changes R7. to refer to “Requirement 6” instead of “Requirement 7”	Errata
2	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 1, 2006	Corrected numbering in Section A.4. “Applicability.”	Errata
2	October 1, 2007	Added to Section 1 inadvertently omitted “4.3. Load-Serving Entities	Errata
2.1	October 29, 2008	BOT adopted errata changes; updated version number to “2.1”	Errata
2.1	May 13, 2009	FERC Approved	Revised
3	June 4, 2010	Modified to address Order No. 693 Directives contained in paragraphs 582.	Revised.
3	August 5, 2010	Adopted by NERC Board of Trustees	New
3.1	March 8, 2012	Errata adopted by Standards Committee; (Updated title of Attachment 1 and changed	Errata

		references to Attachment 1 throughout Standard from "Attachment 1-EOP-002-0 Energy Emergency Alert Levels" to "Attachment 1-EOP-002 Energy Emergency Alerts". Removed parenthetical in Requirement R9 referencing a retired Attachment in IRO-006)	
3.1	September 13, 2012	FERC Approved	Errata

Attachment 1-EOP-002
Energy Emergency Alerts

Introduction
This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

1.1. **Situations for initiating alert.** An Energy Emergency Alert may be initiated for the following reasons:

- When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
- The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. **Notification.** A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction
To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining energy emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. Alert 1 — All available resources in use.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **Alert 2 — Load management procedures in effect**.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
  - Public appeals to reduce demand.
  - Voltage reduction.
  - Interruption of non-firm end use loads in accordance with applicable contracts[1].
  - Demand-side management.
  - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers**.**

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

2.4 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform

[1] For emergency, not economic, reasons.

the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 **Notification of ATC adjustments**. Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.

2.4.2 **Availability of generation redispatch options**. Available generation redispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.

2.4.3 **Evaluating impact of current transmission loading relief events.** The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.

2.4.4 **Initiating inquiries on reevaluating SOLs and IROLs**. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.

2.5 **Coordination of emergency responses.** The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

2.6 **Energy Deficient Entity actions.** Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:

2.6.1 **All available generation units are on line**. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 **Purchases made regardless of cost**. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 **Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed**. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.

2.6.4 **Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 — Firm load interruption imminent or in progress.

Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 **Continue actions from Alert 2**. The Reliability Coordinators and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Energy Deficient Entity obligations. The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 Notification of other parties. Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers’ energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

4.1. Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

Entity experiencing energy deficiency (if different from Balancing Authority):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other Balancing Authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. **All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.**

2. **All firm and nonfirm purchases were made regardless of cost.**

3. **All nonfirm sales were recalled within provisions of the sale agreement.**

4. **Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.**

5. **Available load reduction programs were exercised (public appeals, voltage reductions, etc.).**

6. **Operating Reserves being utilized.**

Comments:

Reported By: **Organization:**

Title:

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard EOP-002-3.1 — Capacity and Energy Emergencies

United States

Standard	Requirement	Enforcement Date	Inactive Date
EOP-002-3.1	All	09/13/2012	

A. Introduction

1. **Title:** **Load Shedding Plans**
2. **Number:** EOP-003-2
3. **Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection.
4. **Applicability:**
   - **4.1.** Transmission Operators.
   - **4.2.** Balancing Authorities.
5. **Effective Date:** One year following the first day of the first calendar quarter after applicable regulatory approvals (or the standard otherwise becomes effective the first day of the first calendar quarter after NERC Board of Trustees adoption in those jurisdictions where regulatory approval is not required).

B. Requirements

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection. *[Violation Risk Factor: High]*

R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required. *[Violation Risk Factor: High]*

R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities. *[Violation Risk Factor: High]*

R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels. *[Violation Risk Factor: High]*

R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown. *[Violation Risk Factor: High]*

R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load. *[Violation Risk Factor: High]*

R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions. *[Violation Risk Factor: High]*

R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or

Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency. *[Violation Risk Factor: High]*

C. Measures

M1. Each Transmission Operator that has or directs the deployment of undervoltage load shedding facilities, shall have and provide upon request, its automatic load shedding plans. (Requirement 2)

M2. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility
Regional Reliability Organizations shall be responsible for compliance monitoring.

1.2. Compliance Monitoring
One or more of the following methods will be used to assess compliance:

- Self-certification (Conducted annually with submission according to schedule.)
- Spot Check Audits (Conducted anytime with up to 30 days notice given to prepare.)
- Periodic Audit (Conducted once every three years according to schedule.)
- Triggered Investigations (Notification of an investigation must be made within 60 days of an event or complaint of noncompliance. The entity will have up to 30 days to prepare for the investigation. An entity may request an extension of the preparation period and the extension will be considered by the Compliance Monitor on a case-by-case basis.)

1.3. Additional Reporting Requirement

No additional reporting required.

1.4. Data Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.

Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.

The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.5. Additional Compliance Information
None

2. Violation Severity Levels

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R1.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
R2	N/A	N/A	N/A	The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the requirement.
R3.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
R4.	N/A	N/A	N/A	The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or power flow levels) listed in the requirement.
R5.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.

R#	Lower VSL	Moderate VSL	High VSL	Severe VSL
R6.	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.
R7.	The Transmission Operator did not coordinate automatic undervoltage load shedding with 5% or less of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.	The Transmission Operator did not coordinate automatic undervoltage load shedding with more than 15% of the types of automatic actions described in the Requirement.
R8.	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.

E. **Regional Differences**

None identified.

Version History

Version	Date	Action	Change Tracking
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed “Proposed” from Effective Date	Errata
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 4, 2010	Adopted by Board of Trustees; Modified R4, R5, R6 and associated VSLs for R2, R4, and R7 to clarify that the requirements don’t apply to automatic underfrequency load shedding.	Revised to eliminate redundancies with PRC-006-1
2	May 7, 2012	FERC Order issued approving EOP-003-2 (approval becomes effective July 10, 2012)	

*** FOR INFORMATIONAL PURPOSES ONLY ***

Enforcement Dates: Standard EOP-003-2 — Load Shedding Plans

United States

Standard	Requirement	Enforcement Date	Inactive Date
EOP-003-2	All	10/01/2013	

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Standards Announcement

Project 2009-03 Five-Year Review of Emergency Operations Standards

Comment Period: August 6, 2013 – September 19, 2013

Now Available

A 45-day comment period for **Project 2009-03 Emergency Operations Standards** is open through **8 p.m. Eastern on Thursday, September 19, 2013**. The Standards Committee assigned eight subject matter experts to review the EOP standards as part of NERC's obligation to conduct periodic reviews of its standards. The five-year review team recommends certain revisions to the EOP standards to provide greater clarity and to sharpen industry focus on tasks that have a more direct impact on reliability. As required by the NERC Standard Processes Manual, this recommendation is being posted for stakeholder comment prior to being finalized and submitted to the Standards Committee.

Background information, including other supporting documents for this project, can be found on the project page. Please contact Laura Anderson, the standards developer, or a member of the EOP five-year review team if you would like additional information.

Instructions for Commenting

A 45-day comment period is open through **8 p.m. Eastern on Thursday, September 19, 2013.** Please use the electronic form to submit comments. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps

The Emergency Operations five-year review team will consider all comments received during the 45-day comment period and, if needed, make revisions to the five-year review template(s). If the comments do not show the need for significant revisions, the recommendation(s) will proceed to a final recommendation.

Standards Development Process

The Standard Processes Manual contains all the procedures governing the standards development process. The success of the NERC standards development process depends on stakeholder participation. We extend our thanks to all those who participate.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, at wendy.muller@nerc.net or at 404-446-2560.

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Individual or group. (25 Responses)
Name (15 Responses)
Organization (15 Responses)
Group Name (10 Responses)
Lead Contact (10 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (0 Responses)
Comments (25 Responses)
Question 1 (24 Responses)
Question 1 Comments (25 Responses)
Question 2 (22 Responses)
Question 2 Comments (25 Responses)
Question 3 (22 Responses)
Question 3 Comments (25 Responses)
Question 4 (15 Responses)
Question 4 Comments (25 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
No
EOP-001 R6.4 should be deleted. There should already be processes in place to deliver electrical energy. This should be left to the generators using normal processes.
Yes
EOP-001-2.1.b Attachment 1 should be further reviewed as it relates to the GOP in light of recent BES events, specifically Cold Weather Events. Also, add EOP-003 into the merger of EOP-001 & EOP-002. It seems to me that the justification for merging EOP-001-2.b (Emergency Operations Planning) and EOP-002-3.1 (Capacity and Energy Emergencies) into one standard (which I agree with) would also apply to including EOP-003-3 (Load Shedding Plans) in the merger. There are redundancies between EOP-001 and EOP-003 that could be eliminated. With the recommended elimination of R2, R4, R5, R6 & R7 from EOP-003-2, there would only be three requirements (R1, R3 & R8) to merge into EOP-001. Recommend that the remaining requirements (R1, R3 & R8) be merged into EOP-001.
Individual
Nazra Gladu
Manitoba Hydro
Yes
Yes
Yes
Yes
Individual
John Seelke
Public Service Enterprise Group
No
We disagree with the statement on p. 4 regarding a review of “Attachment 1 as it relates to the GOP in light of recent BES events (Cold Weather Event).” An effort was initiated in Project 2013-01 Cold Weather, but that project was halted due to inadequate stakeholder support. Nevertheless, item #10 in Attachment 1-EOP-001 does need to be reworded because as written because a BA or TOP plan cannot include “plans to winterize units and plants during extreme cold weather” because a BA or TOP has no control over generators with regard to their winterization efforts. We offer this change to the second sentence which would make it acceptable for compliance by a BA or TOP: “This should include recommendations to generating resources to winterize units and plants in preparation for extreme cold weather.” Since the statement above is the only issue that would involve a Generator Operator, if it is changed as recommended we also recommend removing Generator Operator from the first sentence on p. 4 – the phrase “Transmission Operator, Generator Operator, and Reliability Coordinator” should be replaced with “Transmission Operator, Balancing Authority, and Reliability Coordinator.”

Yes
Yes
No
Individual
Michelle R. D'Antuono
Occidental Energy Ventures Corp. (representing Oxy's NERC registered entities)
No
Occidental Energy Ventures Corp supports the strategy the review team has taken to eliminate ambiguity in emergency operations planning. It is clear that a significant amount of redundancy exists in the standards – and there is a pressing need to specify the roles that operating entities must play in the process. However, it was our understanding that Generator Operator preparedness for an extreme cold weather event – originally captured in Project 2013-01 – had been deferred to the local authorities (e.g.; the Public Utility Commissions). With the intense attention they have put on this issue since the 2011 winter storm in the Southwest U.S., it is not clear that we should add redundant continent-wide requirements – particularly because the approach varies considerably by locale. It serves no useful purpose to scrutinize the cold weather preparedness plans of northern-based GOPs, which are far more routine events at the higher latitudes. Furthermore, per the direction of the RISC, NERC issued a Cold Weather Guideline earlier this year.
Individual
Michael Falvo
Independent Electricity System Operator
No
We do not agree with the removal of EOP-001-2.1b, R3.2 for the following reasons: a. Attachment 1 of this standard lists items for consideration to be included in an emergency plan. R3.2 is important because it says that an emergency plan shall include a list of controlling actions to resolve the emergency (in our case, this is the EOSCA list). b. Load reduction timelines are not as explicit in BAL-002 R2, as it is in EOP-001-2.1b R3.2 c. BAL-002 only applies to BAs – whereas EOP-001-2.1b applies to TOPs and BAs. Emergencies apply to both adequacy shortfalls as well as transmission-related issues.
No
We agree with the recommendation for R1, but not for R6 and R9. We want to point out that retiring R6 may result in not having a requirement anywhere regarding the actions needed when a BA fails to meet DCS since the latest draft BAL-002-2 does not have this requirement or convey any needs for remedial actions when a BA fails to meet DCS. We suggest the 5-Year Review Team or the SDT to keep this in mind and re-evaluate the need to keep or remove R6. Regarding R9, the technology change allows removal of a good number of the sub-requirements, but there is a need for the LSE to request the RC to issue a EEA, which may not be covered by the e-tag spec and/or other automatic communication protocol. We suggest the 5-Year Review Team or the SDT to re-evaluate this.
Yes
We agree with the proposed retirement of R6, and the mapping of R2, R4 and R7 to another standard, but suggest that the 5-Year Review Team or the SDT consider revising R1 to take care of some of the detailed requirement in R6 which implies manual load shedding after UFLS operations. We do not agree with the removal of EOP-003-2 R5 because this requirement implies that any manual load shedding to be implemented shall not include any load that is also connected to UFLS relays. This detail is not mentioned in R1, as the EOP FYRT have recommended. We suggest to include this detail (excluding load that is selected for UFLS) in R1 if the SDT wishes to retire R5. In addition, R6 as written addresses frequency problems and the results of UFLS operations only. R1 as written does not make this distinction, and it asks for load shedding – automatic and/or manual, to address transmission and resource problems. Without R6 and without revising R1, Responsible Entities may simply rely on automatic load shedding schemes (UFLS and UVLS) to address transmission and resource concerns without taking the next steps to implement manual load shedding after the automatic load shedding operations. We suggest the 5-Year Review Team or the SDT to assess the scope of R1, and revise it as necessary to cover both transmission and resource aspects using automatic and manual load shedding as remedial measures.
Individual
David Thorne
Pepco Holdings Inc
Yes

Yes
Yes
No
Individual
Bill Fowler
City of Tallahassee
Yes
Yes
Yes
Individual
Dave Willis
Idaho Power Company
Yes
Yes
Yes
Yes
Idaho Power likes the realistic look at standards for Performance-based results. The elimination of the redundant requirements makes revising these standards a worthwhile project.
Group
Dominion
Connie Lowe
Yes
No
Dominion does not agree that R6 is redundant with BAL-002-1a. Only R6.1 and R6.2 could be considered to be redundant (and even then, implicitly, not explicitly).
Yes
Yes
Dominion does not agree with adding GOP to the suggested combination of EOP-001-2.b and EOP-002-3.1. Nothing in the purpose statements of the cited standards, or the FERC directives relative to these standards indicates that reliability would be improved by expanding to these functions. It is the responsibility of the entities responsible for 'wide area' reliability (BA, RC and TOP) to insure that they request operating information necessary for them to carry out their functions. These already have the authority to require GO/GOPs provide information requested and to follow the instructions given in reliability standards IRO-001-3, TOP-001-2, and TOP-003-2.
Individual
Thomas Foltz
American Electric Power
Yes
Yes
Yes

Individual
Alice Ireland
Xcel Energy
No
R3.3 to identify coordinated tasks should also be looked at to be retired. It is potentially redundant with R6 to coordinate plans since presumably if plans were coordinated, the tasks beneath each plan would be coordinated as well.
Yes
Yes
Yes
Attachment 1 of EOP-001-2.1b needs to be clarified for responsibilities of all applicable entities. As written it is unclear what items BAs and TOPs should be responsible for. Additionally, Attachment 1 should be reviewed for redundancy as well. Items 1, 2, and 7 have significant overlap since the fuel supply and inventory plan probably includes fuel switching capabilities and optimizing fuel supply. Items 4, 5, 6, 9, 12, 13 all cover load curtailment or load management and are too specific. These items should be combined with general guidelines for what is expected when considering load management. Items 3, 10, and 11 also have substantial overlap.
Group
PacifiCorp
Kelly Cumiskey
Yes
Yes
Yes
No
PacifiCorp appreciates the opportunity to provide input for this project and looks forward to the next step in the process.
Group
SERC OC Review Group
Jim Case
Yes
EOP-001-2.1b R1 should eliminate the obligation for BAs to establish “provisions for obtaining emergency assistance from remote BAs.” Regardless of the definition of “remote” as addressed in the interpretation, reliability standards do not need to impose a requirement on BAs to pre-arrange sources of emergency assistance from non-adjacent BAs. In fact, adjacency should not be a parameter addressed by the Requirement, as long as adequate delivery arrangements are in place. Consider eliminating R2.3 due to the redundancy with EOP-003-2 and PRC-010-0 We understand that R4 will be included in the merger of EOP-001-2.1b and EOP-002-3.1.
Yes
R7 requires revision if R6 is retired. Current R7: Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall: Would the FYRT provide further clarification on whether R8 is solely applicable to RC actions regarding issuing of alerts? If not consider splitting the requirement. Example follows: R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 “Energy Emergency Alerts.” Possible new Requirement: “The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.”
Yes
The FYRT is requested to consider renaming the standard to reflect the execution focus of the standard with the proposed revisions.
EOP-008-1: Please consider recommending a revision of EOP-008-1 to allow planned loss of redundancy for periods greater than two weeks without requiring the construction of a tertiary facility. As unplanned losses of redundancy are allowed to extend for six months before requiring a resolution plan to be submitted to the RE [R8], it does not make sense to restrict maintenance activities to only those that can be executed in under two weeks without requiring tertiary facilities to be constructed [R3 and R4, bullet one]. EOP-005-2: Consider retiring EOP-005-2, R2.1, as it appears redundant with NUC-001-2. Training: The FYRT is requested to review and eliminate any training requirements in the EOP standards (not

reviewed during the 5 year process) as they are covered in the PER standards. The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
Yes
Yes
Yes
Austin Energy (AE) provides the following for consideration: (1) Attachment 1 should be reviewed and revised to provide clarity as to which elements apply to the TOP and which to the BA. (2) Add clarifying language to indicate whether the “emergency plans” in R3-R6 are those “operating agreements” and “set[s] of plans” required by R1 and R2, respectively. As currently used, the term “emergency plans” is broad and undefined.
Group
Duke Energy
Colby Bellville
Yes
Yes
With the understanding that BAL-001-2 will ultimately become enforceable, pending BOT and FERC approval, Duke Energy agrees with the removal of R6.
Yes
Individual
Karen Webb
City of Tallahassee - Electric Utility
Yes
Yes
Yes
Yes
Individual
Bob Thomas
Illinois Municipal Electric Agency
Yes
Yes
Illinois Municipal Electric Agency (IMEA) appreciates the EOP Five-Year Review Team's comprehensive review and recommendations. NERC's uniform objectives and process for review and development of high quality, results-based Reliability Standards is very encouraging. IMEA comments were limited to EOP-002 since that is the only EOP standard applicable to one of our registered functions.
Individual
Christina Conway
Oncor Electric Delivery

Yes
Oncor concurs with the EOP FYRT recommendations. However, Oncor further suggests the inclusion of the following additional recommendations. In alignment with one of the Paragraph 81 objectives to remove duplication in the Standards, with EOP-003 specifically covering load shedding and EOP-005 specifically covering system restoration from Blackstart Resources, Oncor recommends the incorporation of specific language into EOP-001 excluding both load shedding plans and system restoration plans, ultimately removing the redundancy between EOP-001 and both EOP-003 and EOP-005. Additionally, although Oncor agrees with the EOP FYRT that the Measures section needs review, Oncor specifically recommends that the Measures section expands to better align to each Requirement creating a clear tie back from Measurement to Requirement.
Yes
Yes
Similar to EOP-001, Oncor agrees with the EOP FYRT that the Measures section needs review. Oncor specifically recommends that the Measures section expands to better align to each Requirement creating a clear tie back from Measurement to Requirement.
Group
Florida Municipal Power Agency
Frank Gaffney
No
R2, 2.1 is redundant with EOP-002, should not apply to TOPs, and should be deleted R2, 2.3 is redundant with EOP-003 and should be deleted FMPA supports merging EOP-001 with EOP-002, but, wonder is there ought to also be some changes to EOP-003 and EOP-005 to accommodate the requirements applicable in EOP-001 to TOPs.
No
R1 is possibly the only requirement that gives the BA clear decision making authority. If that is the case, it should not be deleted without modifying another standard to give the BA that authority. We appreciate the recognition of the overlap of this standard with the BAL standards. We encourage the team to also see if there is overlap with the NAESB WEQ standard on Transmission Loading Relief concerning R9.
Yes
FMPA also wonders if EOP-003 can become a TOP only standard for manual load shedding since load shedding for BAs is really only for capacity/energy emergencies and should be part of EOP-002.
Group
ACES Standards Collaborators
Ben Engelby
No
(1) We agree with the Five Year Review Team (FYRT) recommendations to retire several requirements under Paragraph 81 criteria and to combine EOP-001 and EOP-002. However, we still have additional comments for revising EOP-001, which are stated below. (2) The Commission directed EOP-001 to be revised to have a clear delineation between the TOP and BA actions. We do not see how these directives are being answered or accounted for in the proposed revisions. (3) Requirement R1: We recommend including revisions to capitalize "adjacent BAs" to reflect the NERC glossary term. (4) Requirement R2: EOP-001-2.1b R2.3 is redundant with EOP-003-1 R8 and meets P81 criteria B7. (5) Requirement R3: We question the recommendation to leave R3.3 intact in the standard. This sub-requirement is ambiguous. What does "coordinate tasks" mean? Several requirements require "coordination" (R3.3, R6). Does R1 satisfy coordination? If there are operating agreements in place as required in R1, then there must have been some sort of coordination, which would render the additional tasks as being redundant under Paragraph 81 criteria B7. Further, there are multiple interpretations of what constitutes coordination, and if an auditor determines that there should be an additional task included in the coordination, there could be compliance implications. We also have concerns that the term "adjacent TOPs and BAs" could have multiple interpretations. While there is a glossary term for "Adjacent Balancing Authority," there is not a defined term for the TOP. We ask the FYRT to consider making a recommendation to revise the standard to clarify coordination aspects and adjacent entities. (6) Requirement R5: Annual reviews are administrative in nature and meet P81 criteria B1. Further, there is additional inconsistent language between "adjacent" and "neighboring" entities within this standard. The requirement is ambiguous and could be misinterpreted to include other entities than those identified by the applicable TOP and BA. (7) Requirement R6: If the sub-requirements are retired under P81, then the entire requirement should be retired. R1 would satisfy any other tasks that remain in R6. (8) We agree that VSLs for R1 are ambiguous and support their revision. How would an entity determine that 25% of the "adjacent" BAs or TOPs were not coordinated with or an operating agreement did not exist? Furthermore, the VSLs do not reflect what is needed for reliability. Consider a small 100 MW BA that is interconnected to a large 50,000 MW BA and another small BA with 150 MW of load. Not having an agreement with the large BA would be a reliability concern. An agreement with the small adjacent BA would do little to support reliability and is not a reliability concern. Yet, the VSLs imply that the 100 MW BA would be in violation of the requirement for not having an agreement with both BAs. These VSLs need to be revised as well. (9) The FYRT should also

recommend revising the standard to address the interpretations. A standard should not go through the standards development process and retain any interpretations. The FYRT should include this aspect in its recommendation. (10) Any modifications to EOP-001 R1 should be carefully considered and should avoid the need for BA to immediately re-negotiate their operating agreements. If changes are made to the requirement that compel certain elements to be included, any operating agreement that does not include these agreements will have to be renegotiated.
No
(1) We agree with the FYRT for retiring several requirements under P81 criteria and combining EOP-001 and EOP-002. However, we have additional comments for revising EOP-002 for consideration. (2) R1: we agree with the recommendation to retire R1. (3) R2: Wouldn't the implementation of an emergency plan be included in EOP-001 R1? This requirement should be removed because it is redundant. If a BA did not take appropriate actions to reduce an emergency "as described in its plan" the BA would be in violation of EOP-001 R1. This requirement poses double jeopardy risk. (4) R3: How does a BA communicate "future system conditions" to its RC? This phrase is impossible to comply with, because communicating future conditions could only be a projection of what may occur. How far into the future? Five minutes? Three hours? Two weeks? The BA should only be required to communicate current system conditions, as that is all they could possibly know. (5) R4: In this requirement, the BA that has recognized its system conditions could lead to an emergency and should follow its emergency operating plan, which is required in EOP-001 R1. There is no need for this requirement. Again, this requirement poses a double jeopardy risk. (6) R5: This requirement is redundant with BAL-002 which requires a BA to recover from the loss of a resource within 15 minutes and the 30-minute BAAL limits established in the new BAL-001-2. (7) R6: We agree with the recommendation to retire R6 and offer additional support for its retirement. Many of the actions stated are not appropriate to comply with DCS as they may be contrary to necessary actions to support reliability or they simply aren't timely. For instance, literally loading all available generation may result in an overgeneration situation per R6.1 Reduction of load through public appeals is not going to be effective in time to respond to DCS at it takes time to issue a public appeal and then for the public to respond. Curtailing firm loads is an inappropriate response to comply with DCS or to return ACE to balance if there are no SOL or IROL violations, no indication of stability issues and no frequency issues. Curtailment of firm load is a serious issue and should only be performed when necessary to address imminent reliability threats. Failing to return ACE to zero is not necessarily an imminent reliability threat. (8) R7: If R6 is retired, R7 should be retired as well because it is dependent upon R6. R7 states, "Once the BA has exhausted the steps listed in R6…" Manual firm load shedding is covered by EOP-003 and is also covered in R6.6 which covers reducing load through "curtailing … firm loads", and is therefore redundant. Declaring an EEA should be in the BA's emergency plan and does not need to be a separate requirement. Furthermore, manually shedding firm load is a serious reliability issue and should only be performed to address imminent reliability threats and should not be performed for the sole purpose of returning ACE to zero per R7.1 unless there are other conditions to indicate a significant threat to reliability such as an SOL or IROL violation or low frequency. Shedding load for the sole purpose of returning ACE to zero will result in less reliability not more because end load will be interrupted unnecessarily at time. Furthermore, the R7.1 does not even reflect the DCS requirement that the BA should return its ACE to the lower of its pre-disturbance value or zero. (9) R8: Wouldn't R8 fall under the RC emergency plan? This is another requirement that does not need to be a separate requirement. (10) R9: We agree with the recommendation to retire R9 not only because the need is obviated by the updated E-tag spec but primarily because it is in fact a business practice and deals with prioritizing transmission service per FERC approved tariffs. Deficient BA can rely on their operating agreements in EOP-001 R1 to address energy and capacity deficiencies. (11) Finally, EOP-002 does not have VSLs, VRFs, or Time Horizons. These elements should be added when the standard is revised.
No
(1) While we agree that there are several requirements that should be retired, we have additional comments for revising EOP-003. (2) R1: This requirement should be combined with R8 for having a plan to shed load. Both requirements compel load shed to respond to similar situations. R1 requires responding to an "uncontrolled failure" or "cascading outages" while R8 requires response to "real-time emergencies." "Uncontrolled failure" and "cascading outages" would constitute real-time emergencies. The only other difference is that R8 compels that the load shed must be timely. That is implied in R1. Responsible Entities should be subject to complying with its load shedding plan. (3) We agree that R2, R4, and R7 should be incorporated with PRC-010. (4) R3: Similar to R2 (UVLS), why did the FYRT not recommend moving R3 to PRC-006 for UFLS? (5) We agree that R5 and R6 should retired under P81 criteria. (6) R8: as stated above, we ask the FYRT to consider recommending that R1 and R8 be combined to address load shedding by having a plan for both automatic and manual load shedding and to comply with its plan. (7) We agree with the FYRT that measures and data retention should be reviewed and updated.
Yes
(1) We question why the team has not reviewed the other EOP standards. There are multiple requirements in the other EOP standards that would also meet Paragraph 81 criteria and should be revised. The five year review team should take this opportunity to make recommendations for the entire set of EOP standards. (2) We also recommend that the review team take the Independent Expert Review into consideration. There are several EOP modifications based on the expert's recommendations. We are concerned that the review teams are not aware of or did not consider these expert recommendations. (3) Thank you for the opportunity to comment.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes

Yes
Group
Southern Company
Wayne Johnson
Yes
Southern agrees with the SERC OC comments.
Yes
Southern agrees with the SERC OC comments.
Yes
Southern agrees with the SERC OC comments.
Yes
Southern agrees with the SERC OC comments.
Individual
Scott Langston
City of Tallahassee
Yes
Yes
Yes
Group
SPP Standards Review Group
Robert Rhodes
No
We recommend retiring R2.3 in EOP-001-2.1b since it is redundant with EOP-003-2. We support the effort to combine EOP-001 and EOP-002.
No
The Independent Experts Review Project recommended that R2 and R3 of EOP-002 be retired. This recommendation needs to be factored into the 5-Year Review Team's recommendations. Also, with the proposed retirement of R6, R7 needs to be revised to eliminate the reference to R6 and should instead refer to criteria spelled out in Attachment 1. In this process, R7.1 needs to be retired since it is redundant with EOP-003-2.
No
We recommend that the coordination of load shedding plans as called for in R3 be expanded upon such that it clarifies what the expectation for coordination is. For example, if it's simply sharing load shedding plans, it should be retired just as R5 in EOP-001-2.1b was. Perhaps a revised measure would add the needed clarity. Regardless, it needs to be clearer just what the expectation is. We support the recommendation to move R2, R4 and R7 to PRC-010.
No
Group
ISO/RTO Council Standards Review Committee
Greg Campoli
Yes
No
We agree with the recommendation for R1, but not for R6 and R9. Retiring R6 may result in not having a requirement anywhere regarding the actions needed when a BA fails to meet DCS since the latest draft BAL-002-2 does not have this requirement or convey any needs for remedial actions when a BA is unable to meet DCS. We suggest the 5-Year Review Team or the SDT to keep this in mind and re-evaluate the need to keep or remove R6. Regarding R9, the technology change allows removal of a good number of the sub-requirements, but there is a need for the LSE to request the RC to

issue an EEA, which may not be covered by the e-tag spec and/or other automatic communication protocol. We suggest the 5-Year Review Team or the SDT to re-evaluate this. Note: PJM, ISO-NE and CAISO do not support this comment.
Yes
We agree with the proposed retirement of R5 and R6, and the mapping of R2, R4 and R7 to another standard, but suggest that the 5-Year Review Team or the SDT consider revising R1 to take care of some of the detailed requirement in R6 which implies manual load shedding after UFLS operations. R6 as written addresses frequency problems and the results of UFLS operations only. R1 as written does not make this distinction, and it asks for load shedding – automatic and/or manual, to address transmission and resource problems. Without R6 and without revising R1, Responsible Entities may simply rely on automatic load shedding schemes (UFLS and UVLS) to address transmission and resource concerns without taking the next steps to implement manual load shedding after the automatic load shedding operations. We suggest the 5-Year Review Team or the SDT to assess the scope of R1, and revise it as necessary to cover both transmission and resource aspects using automatic and manual load shedding as remedial measures. We further suggest the 5-Year Review Team or the SDT consider merging EOP-003-2 (Load Shedding Plans) into EOP-001-2.b (Emergency Operations Planning). The justification for the 5-Year Review Team proposal to merge EOP-002-3.1 (Capacity and Energy Emergencies) into EOP-001-2.b also applies to merging EOP-003-3 into EOP-001-2.b. This would eliminate redundancies between EOP-001 and EOP-003. With the recommended elimination of R2, R4, R5, R6 & R7 from EOP-003-2, there would only be three requirements (R1, R3 & R8) left to merge into EOP-001.
No

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments

Project 2009-03 Emergency Operations

The Project 2009-03 Emergency Operations Five-Year Review Team (EOP FYRT) thanks all commenters who submitted comments on the EOP-001-2.1b, EOP-002-3.1, and EOP-003-2 standards. The standards were posted for a 45-day comment period from August 6, 2013 through September 19, 2013. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 25 sets of responses, including comments from approximately 94 different people from approximately 58 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Mark Lauby, at 404-446-2560 or at mark.lauby@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/files/Appendix_3A_StandardsProcessesManual_20120131.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Greg Campoli	New York Independent System Oeprator	NPCC	2
3.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
4.	Don Weaver	New Brunswick System Operator	NPCC	2
5.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
6.	Mike Garton	Dominion Respources Services, Inc.	NPCC	5
7.	Kathleen Goodman	ISO - New England	NPCC	2
8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1
10.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Randy MacDonald	New Brunswick Power Transmission	NPCC	9
14.	Bruce Metruck	New York Power Authority	NPCC	6
15.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
16.	Lee Pedowicz	Northeast Power Coordinating Committee	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si-Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
20.	Brian Robinson	Utility Services	NPCC	8
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10

2.	Group	Connie Lowe	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	Dominion	RFC	5, 6
2.	Mike Garton	Dominion	NPCC	5, 6
3.	Randi Heise	Dominion	MRO	6
4.	Michael Crowley	Dominion	SERC	1, 3, 5, 6

3.	Group	Kelly Cumiskey	PacifiCorp	X		X		X	X				

No additional responses provided.

4.	Group	Jim Case	SERC OC Review Group	X		X			X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mike Bryson	PJM	SERC	2
2.	Marsha Morgan	Southern	SERC	1, 5
3.	William Berry	OMU	SERC	3

5.	Group	Colby Bellville	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils	Duke Energy	RFC	1
2.	Lee Schuster	Duke Energy	FRCC	3
3.	Dale Goodwine	Duke Energy	SERC	5
4.	Greg Cecil	Duke Energy	RFC	6

6.	Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Timothy Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Services	FRCC	3
7.	Stanley Rzad	Keys Energy Services	FRCC	3

				1	2	3	4	5	6	7	8	9	10
7.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Shari Heino	Brazos Electric Power Cooperative, Inc.	SERC	1, 5
2.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
3.	Megan Wagner	Sunflower Electric Power Corporation	SPP	1

				1	2	3	4	5	6	7	8	9	10
8.	Group	Wayne Johnson	Southern Company	X		X		X	X				

No additional responses provided.

				1	2	3	4	5	6	7	8	9	10
9.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Allan George	Sunflower Electric Power Corporation	SPP	1
3.	Mark Hamilton	Oklahoma Gas & Electric	SPP	1, 3, 5
4.	John Hare	Oklahoma Gas & Electric	SPP	1, 3, 5
5.	Don Hargrove	Oklahoma Gas & Electric	SPP	1, 3, 5
6.	Shawn Jacobs	Oklahoma Gas & Electric	SPP	1, 3, 5
7.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
8.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
9.	Mike Kidwell	Empire District Electric	SPP	1
10.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
11.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
12.	Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5
13.	James Nail	City of Independence, MO	SPP	3
14.	Terri Pyle	Oklahoma Gas & Electric	SPP	1, 3, 5
15.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
16.	Sean Simpson	Board of Public Utilities of Kansas City, KS	SPP	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

17.	Sing Tay	Oklahoma Gas & Electric	SPP	1, 3, 5
18.	Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6
19.	Mark Trumble	Omaha Public Power District	MRO	1, 3, 5
20.	Jim Useldinger	Kansas City Power & Light	SPP	1, 3, 5, 6
21.	Scott Williams	City Utilities of Springfield	SPP	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Greg Campoli	ISO/RTO Council Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Kathleen Goodman	ISO-NE	NPCC	2
2.	Ali Miremandi	CAISO	WECC	2
3.	Cheryl Moseley	ERCOT	ERCOT	2
4.	Charles Yeung	SPP	SPP	2
5.	Ben Li	IESO	NPCC	2
6.	Terry Bilke	MISO	MRO	2
7.	Al DiCaprio	PJM	RFC	2

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Individual	Nazra Gladu	Manitoba Hydro	X		X		X	X				
12.	Individual	John Seelke	Public Service Enterprise Group	X		X		X	X				
13.	Individual	Michelle R. D'Antuono	Occidental Energy Ventures Corp. (representing Oxy's NERC registered entities)					X					
14.	Individual	Michael Falvo	Independent Electricity System Operator		X								
15.	Individual	David Thorne	Pepco Holdings Inc	X		X							
16.	Individual	Bill Fowler	City of Tallahassee			X							
17.	Individual	Dave Willis	Idaho Power Company	X									
18.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
19.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
20.	Individual	Andrew Gallo	City of Austin dba Austin Energy	X		X	X	X	X				
21.	Individual	Karen Webb	City of Tallahassee - Electric Utility					X					
22.	Individual	Bob Thomas	Illinois Municipal Electric Agency				X						
23.	Individual	Christina Conway	Oncor Electric Delivery	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
24.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
25.	Individual	Scott Langston	City of Tallahassee	X									

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Agree	Supporting Comments of “Entity Name”
N/A	N/A	N/A

1. **Do you agree with the recommendation regarding EOP-001-2.1b? If not, please explain specifically what aspects of the recommendation you disagree with.**

Summary Consideration:

The EOP FYRT concurs with the following comments:

- Terms in the standard should be clarified
- The directives from FERC should be met
- Attachment 1, as well as the applicability of the individual items, should be reviewed

The EOP FYRT received agreement from commenters on the suggested requirements that will be retired under P81. Florida Municipal, SPP Standards Group, and ACES Standards Collaborators believe that additional requirements (Requirements R2.1 and R2.3) should be retired under the P81 criteria. However, the EOP FYRT's evaluation concluded that Requirements R2.1 and R2.3 did not qualify for retirement under the P81 criteria. In addition, the EOP FYRT's recommendation is in alignment with the Independent Expert Review Panel report.

The Independent Electricity System Operator commented that Requirement R3.2 should not be removed. However, the EOP FYRT believes that removal of Requirement R3.2 is valid based on: (1) the language in Attachment 1; (2) by having the SAR combine EOP-002-3.1 with EOP 001-2.1b; and (3) support by industry commenters. The EOP FYRT strongly recommends that the future EOP SDT consider merging and revising EOP-001-2.1b and EOP-002-3.1 into a single standard. The EOP FYRT is recommending the merging and revising of EOP-001-2.1b and EOP-002-3.1 because it will not only streamline and clarify the requirements after applying the Paragraph 81 criteria, but also will invoke the continuous improvement cycle of the reliability standards towards Results Based Standards (RBS) which supports the Reliability Assurance Initiative (RAI) with the objective of moving to a more sustainable Compliance and Enforcement Program. These recommendations are being submitted as part of the SAR to be presented to the Standards Committee.

Organization	Yes or No	Question 1 Comment

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	EOP-001 R6.4 should be deleted. There should already be processes in place to deliver electrical energy. This should be left to the generators using normal processes.
Florida Municipal Power Agency	No	R2, 2.1 is redundant with EOP-002, should not apply to TOPs, and should be deletedR2, 2.3 is redundant with EOP-003 and should be deletedFMPA supports merging EOP-001 with EOP-002, but, wonder is there ought to also be some changes to EOP-003 and EOP-005 to accommodate the requirements applicable in EOP-001 to TOPs.
ACES Standards Collaborators	No	(1) We agree with the Five Year Review Team (FYRT) recommendations to retire several requirements under Paragraph 81 criteria and to combine EOP-001 and EOP-002. However, we still have additional comments for revising EOP-001, which are stated below.(2) The Commission directed EOP-001 to be revised to have a clear delineation between the TOP and BA actions. We do not see how these directives are being answered or accounted for in the proposed revisions.(3) Requirement R1: We recommend including revisions to capitalize "adjacent BAs" to reflect the NERC glossary term. (4) Requirement R2: EOP-001-2.1b R2.3 is redundant with EOP-003-1 R8 and meets P81 criteria B7.(5) Requirement R3: We question the recommendation to leave R3.3 intact in the standard. This sub-requirement is ambiguous. What does "coordinate tasks" mean? Several requirements require "coordination" (R3.3, R6). Does R1 satisfy coordination? If there are operating agreements in place as required in R1, then there must have been some sort of coordination, which would render the additional tasks as being redundant under Paragraph 81 criteria B7. Further, there are multiple interpretations of what constitutes coordination, and if an auditor determines that there should be an additional task included in the coordination, there could be compliance implications. We also have concerns that the term "adjacent TOPs and BAs" could have multiple interpretations. While there is a glossary term for "Adjacent Balancing Authority," there is not a defined term for the TOP. We ask the FYRT to consider making a

Organization	Yes or No	Question 1 Comment
		recommendation to revise the standard to clarify coordination aspects and adjacent entities.(6) Requirement R5: Annual reviews are administrative in nature and meet P81 criteria B1. Further, there is additional inconsistent language between "adjacent" and "neighboring" entities within this standard. The requirement is ambiguous and could be misinterpreted to include other entities than those identified by the applicable TOP and BA.(7) Requirement R6: If the sub-requirements are retired under P81, then the entire requirement should be retired. R1 would satisfy any other tasks that remain in R6.(8) We agree that VSLs for R1 are ambiguous and support their revision. How would an entity determine that 25% of the "adjacent" BAs or TOPs were not coordinated with or an operating agreement did not exist? Furthermore, the VSLs do not reflect what is needed for reliability. Consider a small 100 MW BA that is interconnected to a large 50,000 MW BA and another small BA with 150 MW of load. Not having an agreement with the large BA would be a reliability concern. An agreement with the small adjacent BA would do little to support reliability and is not a reliability concern. Yet, the VSLs imply that the 100 MW BA would be in violation of the requirement for not having an agreement with both BAs. These VSLs need to be revised as well.(9) The FYRT should also recommend revising the standard to address the interpretations. A standard should not go through the standards development process and retain any interpretations. The FYRT should include this aspect in its recommendation.(10) Any modifications to EOP-001 R1 should be carefully considered and should avoid the need for BA to immediately re-negotiate their operating agreements. If changes are made to the requirement that compel certain elements to be included, any operating agreement that does not include these agreements will have to be renegotiated.
SPP Standards Review Group	No	We recommend retiring R2.3 in EOP-001-2.1b since it is redundant with EOP-003-2.We support the effort to combine EOP-001 and EOP-002.
Public Service Enterprise Group	No	We disagree with the statement on p. 4 regarding a review of "Attachment 1 as it relates to the GOP in light of recent BES events (Cold Weather Event)." An effort

Organization	Yes or No	Question 1 Comment
		was initiated in Project 2013-01 Cold Weather, but that project was halted due to inadequate stakeholder support. Nevertheless, item #10 in Attachment 1-EOP-001 does need to be reworded because as written because a BA or TOP plan cannot include “plans to winterize units and plants during extreme cold weather” because a BA or TOP has no control over generators with regard to their winterization efforts. We offer this change to the second sentence which would make it acceptable for compliance by a BA or TOP: “This should include recommendations to generating resources to winterize units and plants in preparation for extreme cold weather.”Since the statement above is the only issue that would involve a Generator Operator, if it is changed as recommended we also recommend removing Generator Operator from the first sentence on p. 4 - the phrase “Transmission Operator, Generator Operator, and Reliability Coordinator” should be replaced with “Transmission Operator, Balancing Authority, and Reliability Coordinator.”
Occidental Energy Ventures Corp. (representing Oxy's NERC registered entities)	No	Occidental Energy Ventures Corp supports the strategy the review team has taken to eliminate ambiguity in emergency operations planning. It is clear that a significant amount of redundancy exists in the standards - and there is a pressing need to specify the roles that operating entities must play in the process.However, it was our understanding that Generator Operator preparedness for an extreme cold weather event - originally captured in Project 2013-01 - had been deferred to the local authorities (e.g.; the Public Utility Commissions). With the intense attention they have put on this issue since the 2011 winter storm in the Southwest U.S., it is not clear that we should add redundant continent-wide requirements - particularly because the approach varies considerably by locale. It serves no useful purpose to scrutinize the cold weather preparedness plans of northern-based GOPs, which are far more routine events at the higher latitudes. Furthermore, per the direction of the RISC, NERC issued a Cold Weather Guideline earlier this year.
Independent Electricity System Operator	No	We do not agree with the removal of EOP-001-2.1b, R3.2 for the following reasons:a. Attachment 1 of this standard lists items for consideration to be included in an emergency plan. R3.2 is important because it says that an emergency plan shall

Organization	Yes or No	Question 1 Comment
		include a list of controlling actions to resolve the emergency (in our case, this is the EOSCA list).b. Load reduction timelines are not as explicit in BAL-002 R2, as it is in EOP-001-2.1b R3.2c. BAL-002 only applies to BAs - whereas EOP-001-2.1b applies to TOPs and BAs. Emergencies apply to both adequacy shortfalls as well as transmission-related issues.
Xcel Energy	No	R3.3 to identify coordinated tasks should also be looked at to be retired. It is potentially redundant with R6 to coordinate plans since presumably if plans were coordinated, the tasks beneath each plan would be coordinated as well.
SERC OC Review Group	Yes	EOP-001-2.1b R1 should eliminate the obligation for BAs to establish "provisions for obtaining emergency assistance from remote BAs." Regardless of the definition of "remote" as addressed in the interpretation, reliability standards do not need to impose a requirement on BAs to pre-arrange sources of emergency assistance from non-adjacent BAs. In fact, adjacency should not be a parameter addressed by the Requirement, as long as adequate delivery arrangements are in place.Consider eliminating R2.3 due to the redundancy with EOP-003-2 and PRC-010-0We understand that R4 will be included in the merger of EOP-001-2.1b and EOP-002-3.1.
Southern Company	Yes	Southern agrees with the SERC OC comments.
Oncor Electric Delivery	Yes	Oncor concurs with the EOP FYRT recommendations. However, Oncor further suggests the inclusion of the following additional recommendations. In alignment with one of the Paragraph 81 objectives to remove duplication in the Standards, with EOP-003 specifically covering load shedding and EOP-005 specifically covering system restoration from Blackstart Resources, Oncor recommends the incorporation of specific language into EOP-001 excluding both load shedding plans and system restoration plans, ultimately removing the redundancy between EOP-001 and both EOP-003 and EOP-005.Additionally, although Oncor agrees with the EOP FYRT that the Measures section needs review, Oncor specifically recommends that the Measures section expands to better align to each Requirement creating a clear tie

Organization	Yes or No	Question 1 Comment
		back from Measurement to Requirement.
Dominion	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
ISO/RTO Council Standards Review Committee	Yes	
Manitoba Hydro	Yes	
Pepco Holdings Inc	Yes	
City of Tallahassee	Yes	
Idaho Power Company	Yes	
American Electric Power	Yes	
City of Austin dba Austin Energy	Yes	
City of Tallahassee - Electric Utility	Yes	
American Transmission Company, LLC	Yes	
City of Tallahassee	Yes	

2. Do you agree with the recommendation regarding EOP-002-3.1? If not, please explain specifically what aspects of the recommendation you disagree with.

Summary Consideration:

The EOP FYRT concurs with the following comments:

- Terms in the standard should be clarified
- The directives from FERC should be met
- Attachment 1, as well as the applicability of the individual items

The EOP FYRT reviewed the comments on EOP-002-3.1. Most commenters agreed with the recommendation that Requirement R6 should be removed in its entirety. However, Dominion, ISO/RTO Council, and Independent Electric System Operator commented that Requirement R6 should remain. Based on P81 criteria, coupled with the recommendations from the Independent Expert Review Panel report, the EOP FYRT maintains that Requirement R6 is redundant and should be retired.

Florida Municipal did not agree that Requirement R1 should be retired, but the majority of the commenters do agree with the retirement and, therefore, the EOP FYRT stands by its recommendation to retire Requirement R1.

ACES Standards Collaborators was supportive of the retirement of those requirements recommended by the EOP FYRT, but also recommends additional requirements for retirement. While the EOP FYRT does not agree with ACES' additional recommendations, the EOP FYRT will recommend that the future EOP SDT considers these recommendations through the SAR and during the review to consolidate EOP-001-2.1b and EOP-002-3.1.

The SPP Standards Review Group recommended that the EOP FYRT include Requirements R2 and R3 for retirement, as identified by the Independent Expert Review Panel report. The EOP FYRT maintains that the retirement of Requirement R1 is necessary for Requirements R2 and R3 to be retained.

ACES Standards Collaborators raised the question as to why the EOP FYRT had reviewed only three of the EOP standards. As many of the EOP standards recently became effective (or had not yet become effective) and have not yet been implemented, a decision was made that they will be reviewed at a later time.

Organization	Yes or No	Question 2 Comment
Dominion	No	Dominion does not agree that R6 is redundant with BAL-002-1a. Only R6.1 and R6.2 could be considered to be redundant (and even then, implicitly, not explicitly).
Florida Municipal Power Agency	No	R1 is possibly the only requirement that gives the BA clear decision making authority. If that is the case, it should not be deleted without modifying another standard to give the BA that authority.We appreciate the recognition of the overlap of this standard with the BAL standards. We encourage the team to also see if there is overlap with the NAESB WEQ standard on Transmission Loading Relief concerning R9.
ACES Standards Collaborators	No	(1) We agree with the FYRT for retiring several requirements under P81 criteria and combining EOP-001 and EOP-002. However, we have additional comments for revising EOP-002 for consideration.(2) R1: we agree with the recommendation to retire R1.(3) R2: Wouldn't the implementation of an emergency plan be included in EOP-001 R1? This requirement should be removed because it is redundant. If a BA did not take appropriate actions to reduce an emergency "as described in its plan" the BA would be in violation of EOP-001 R1. This requirement poses double jeopardy risk.(4) R3: How does a BA communicate "future system conditions" to its RC? This phrase is impossible to comply with, because communicating future conditions could only be a projection of what may occur. How far into the future? Five minutes? Three hours? Two weeks? The BA should only be required to communicate current system conditions, as that is all they could possibly know. (5) R4: In this requirement, the BA that has recognized its system conditions could lead to an emergency and should follow its emergency operating plan, which is required in EOP-001 R1. There is no need for this requirement. Again, this requirement poses a double jeopardy risk.(6) R5: This requirement is redundant with BAL-002 which requires a BA to recover from the loss of a resource within 15 minutes and the 30-minute BAAL limits established in the new BAL-001-2. (7) R6: We agree with the recommendation to retire R6 and offer additional support for its retirement. Many of the actions stated are not appropriate to comply with DCS as they may be

Organization	Yes or No	Question 2 Comment
		contrary to necessary actions to support reliability or they simply aren't timely. For instance, literally loading all available generation may result in an overgeneration situation per R6.1 Reduction of load through public appeals is not going to be effective in time to respond to DCS at it takes time to issue a public appeal and then for the public to respond. Curtailing firm loads is an inappropriate response to comply with DCS or to return ACE to balance if there are no SOL or IROL violations, no indication of stability issues and no frequency issues. Curtailment of firm load is a serious issue and should only be performed when necessary to address imminent reliability threats. Failing to return ACE to zero is not necessarily an imminent reliability threat. (8) R7: If R6 is retired, R7 should be retired as well because it is dependent upon R6. R7 states, "Once the BA has exhausted the steps listed in R6..." Manual firm load shedding is covered by EOP-003 and is also covered in R6.6 which covers reducing load through "curtailing ... firm loads", and is therefore redundant. Declaring an EEA should be in the BA's emergency plan and does not need to be a separate requirement. Furthermore, manually shedding firm load is a serious reliability issue and should only be performed to address imminent reliability threats and should not be performed for the sole purpose of returning ACE to zero per R7.1 unless there are other conditions to indicate a significant threat to reliability such as an SOL or IROL violation or low frequency. Shedding load for the sole purpose of returning ACE to zero will result in less reliability not more because end load will be interrupted unnecessarily at time. Furthermore, the R7.1 does not even reflect the DCS requirement that the BA should return its ACE to the lower of its pre-disturbance value or zero. (9) R8: Wouldn't R8 fall under the RC emergency plan? This is another requirement that does not need to be a separate requirement.(10) R9: We agree with the recommendation to retire R9 not only because the need is obviated by the updated E-tag spec but primarily because it is in fact a business practice and deals with prioritizing transmission service per FERC approved tariffs. Deficient BA can rely on their operating agreements in EOP-001 R1 to address energy and capacity deficiencies.(11) Finally, EOP-002 does not have VSLs, VRFs, or Time Horizons. These elements should be added when the standard is revised.

Organization	Yes or No	Question 2 Comment
SPP Standards Review Group	No	The Independent Experts Review Project recommended that R2 and R3 of EOP-002 be retired. This recommendation needs to be factored into the 5-Year Review Team's recommendations.Also, with the proposed retirement of R6, R7 needs to be revised to eliminate the reference to R6 and should instead refer to criteria spelled out in Attachment 1. In this process, R7.1 needs to be retired since it is redundant with EOP-003-2.
ISO/RTO Council Standards Review Committee	No	We agree with the recommendation for R1, but not for R6 and R9. Retiring R6 may result in not having a requirement anywhere regarding the actions needed when a BA fails to meet DCS since the latest draft BAL-002-2 does not have this requirement or convey any needs for remedial actions when a BA is unable to meet DCS. We suggest the 5-Year Review Team or the SDT to keep this in mind and re-evaluate the need to keep or remove R6. Regarding R9, the technology change allows removal of a good number of the sub-requirements, but there is a need for the LSE to request the RC to issue an EEA, which may not be covered by the e-tag spec and/or other automatic communication protocol. We suggest the 5-Year Review Team or the SDT to re-evaluate this.Note: PJM, ISO-NE and CAISO do not support this comment.
Independent Electricity System Operator	No	We agree with the recommendation for R1, but not for R6 and R9. We want to point out that retiring R6 may result in not having a requirement anywhere regarding the actions needed when a BA fails to meet DCS since the latest draft BAL-002-2 does not have this requirement or convey any needs for remedial actions when a BA fails to meet DCS. We suggest the 5-Year Review Team or the SDT to keep this in mind and re-evaluate the need to keep or remove R6. Regarding R9, the technology change allows removal of a good number of the sub-requirements, but there is a need for the LSE to request the RC to issue a EEA, which may not be covered by the e-tag spec and/or other automatic communication protocol. We suggest the 5-Year Review Team or the SDT to re-evaluate this.
SERC OC Review Group	Yes	R7 requires revision if R6 is retired. Current R7: Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed

Organization	Yes or No	Question 2 Comment
		in sufficient time to resolve the emergency condition, the Balancing Authority shall:Would the FYRT provide further clarification on whether R8 is solely applicable to RC actions regarding issuing of alerts? If not consider splitting the requirement. Example follows: R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." Possible new Requirement: "The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required."
Duke Energy	Yes	With the understanding that BAL-001-2 will ultimately become enforceable, pending BOT and FERC approval, Duke Energy agrees with the removal of R6.
Southern Company	Yes	Southern agrees with the SERC OC comments.
Manitoba Hydro	Yes	
Public Service Enterprise Group	Yes	
Pepco Holdings Inc	Yes	
City of Tallahassee	Yes	
Idaho Power Company	Yes	
American Electric Power	Yes	
Xcel Energy	Yes	
City of Austin dba Austin Energy	Yes	
City of Tallahassee - Electric	Yes	

Organization	Yes or No	Question 2 Comment
Utility		
Illinois Municipal Electric Agency	Yes	
Oncor Electric Delivery	Yes	
City of Tallahassee	Yes	
PacifiCorp	Yes	

3. Do you agree with the recommendation regarding EOP-003-2? If not, please explain specifically what aspects of the recommendation you disagree with.

Summary Consideration:

The EOP FYRT concurs with the following comments:

- Terms in the standard should be clarified
- The directives from FERC should be met
- Attachment 1, as well as the applicability of the individual items should be reviewed

As it relates to ACES Standards Collaborators, the EOP FYRT agrees that Requirements R1 and R8 should be considered for merger and shall include this recommendation in the SAR.

SPP and others commented on the lack of clarity of the requirements. The EOP FYRT also received comments that EOP-003-2 should be combined with EOP-001-2.1b and EOP-002-3.1. The EOP FYRT will recommend that the future EOP SDT consider merging EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 into a single standard. In addition, the EOP FYRT recommends the future EOP SDT evaluate the separation of the functional entity capabilities of the BA and the TOP responsibilities.

Organization	Yes or No	Question 3 Comment
ACES Standards Collaborators	No	(1) While we agree that there are several requirements that should be retired, we have additional comments for revising EOP-003.(2) R1: This requirement should be combined with R8 for having a plan to shed load. Both requirements compel load shed to respond to similar situations. R1 requires responding to an “uncontrolled failure” or “cascading outages” while R8 requires response to “real-time emergencies.” “Uncontrolled failure” and “cascading outages” would constitute real-time emergencies. The only other difference is that R8 compels that the load shed must be timely. That is implied in R1. Responsible Entities should be subject to complying with its load shedding plan.(3) We agree that R2, R4, and R7 should be incorporated with PRC-010.(4) R3: Similar to R2 (UVLS), why did the FYRT not recommend moving R3 to PRC-006 for UFLS?(5) We agree that R5 and R6 should retired under P81 criteria.(6) R8: as stated above, we ask the FYRT to consider

Organization	Yes or No	Question 3 Comment
		recommending that R1 and R8 be combined to address load shedding by having a plan for both automatic and manual load shedding and to comply with its plan.(7) We agree with the FYRT that measures and data retention should be reviewed and updated.
SPP Standards Review Group	No	We recommend that the coordination of load shedding plans as called for in R3 be expanded upon such that it clarifies what the expectation for coordination is. For example, if it's simply sharing load shedding plans, it should be retired just as R5 in EOP-001-2.1b was. Perhaps a revised measure would add the needed clarity. Regardless, it needs to be clearer just what the expectation is.We support the recommendation to move R2, R4 and R7 to PRC-010.
SERC OC Review Group	Yes	The FYRT is requested to consider renaming the standard to reflect the execution focus of the standard with the proposed revisions.
Florida Municipal Power Agency	Yes	FMPA also wonders if EOP-003 can become a TOP only standard for manual load shedding since load shedding for BAs is really only for capacity/energy emergencies and should be part of EOP-002.
Southern Company	Yes	Southern agrees with the SERC OC comments.
ISO/RTO Council Standards Review Committee	Yes	We agree with the proposed retirement of R5 and R6, and the mapping of R2, R4 and R7 to another standard, but suggest that the 5-Year Review Team or the SDT consider revising R1 to take care of some of the detailed requirement in R6 which implies manual load shedding after UFLS operations. R6 as written addresses frequency problems and the results of UFLS operations only. R1 as written does not make this distinction, and it asks for load shedding - automatic and/or manual, to address transmission and resource problems. Without R6 and without revising R1, Responsible Entities may simply rely on automatic load shedding schemes (UFLS and UVLS) to address transmission and resource concerns without taking the next steps to implement manual load shedding after the automatic load shedding operations.

Organization	Yes or No	Question 3 Comment
		We suggest the 5-Year Review Team or the SDT to assess the scope of R1, and revise it as necessary to cover both transmission and resource aspects using automatic and manual load shedding as remedial measures.We further suggest the 5-Year Review Team or the SDT consider merging EOP-003-2 (Load Shedding Plans) into EOP-001-2.b (Emergency Operations Planning). The justification for the 5-Year Review Team proposal to merge EOP-002-3.1 (Capacity and Energy Emergencies) into EOP-001-2.b also applies to merging EOP-003-3 into EOP-001-2.b. This would eliminate redundancies between EOP-001 and EOP-003. With the recommended elimination of R2, R4, R5, R6 & R7 from EOP-003-2, there would only be three requirements (R1, R3 & R8) left to merge into EOP-001.
Independent Electricity System Operator	Yes	We agree with the proposed retirement of R6, and the mapping of R2, R4 and R7 to another standard, but suggest that the 5-Year Review Team or the SDT consider revising R1 to take care of some of the detailed requirement in R6 which implies manual load shedding after UFLS operations. We do not agree with the removal of EOP-003-2 R5 because this requirement implies that any manual load shedding to be implemented shall not include any load that is also connected to UFLS relays. This detail is not mentioned in R1, as the EOP FYRT have recommended. We suggest to include this detail (excluding load that is selected for UFLS) in R1 if the SDT wishes to retire R5.In addition, R6 as written addresses frequency problems and the results of UFLS operations only. R1 as written does not make this distinction, and it asks for load shedding - automatic and/or manual, to address transmission and resource problems. Without R6 and without revising R1, Responsible Entities may simply rely on automatic load shedding schemes (UFLS and UVLS) to address transmission and resource concerns without taking the next steps to implement manual load shedding after the automatic load shedding operations. We suggest the 5-Year Review Team or the SDT to assess the scope of R1, and revise it as necessary to cover both transmission and resource aspects using automatic and manual load shedding as remedial measures.

Organization	Yes or No	Question 3 Comment
Oncor Electric Delivery	Yes	Similar to EOP-001, Oncor agrees with the EOP FYRT that the Measures section needs review. Oncor specifically recommends that the Measures section expands to better align to each Requirement creating a clear tie back from Measurement to Requirement.
Dominion	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
Manitoba Hydro	Yes	
Public Service Enterprise Group	Yes	
Pepco Holdings Inc	Yes	
City of Tallahassee	Yes	
Idaho Power Company	Yes	
American Electric Power	Yes	
Xcel Energy	Yes	
City of Austin dba Austin Energy	Yes	
City of Tallahassee - Electric Utility	Yes	
American Transmission Company, LLC	Yes	

Organization	Yes or No	Question 3 Comment
City of Tallahassee	Yes	

4. **If you have any other comments on the EOP Five-Year Review Recommendations that you have not already mentioned above, please provide them here:**

Summary Consideration:

The EOP FYRT concurs with the following comments:

- Terms in the standard should be clarified
- The directives from FERC should be met
- Attachment 1, as well as the applicability of the individual items, should be reviewed

The EOP FYRT received comments from Northeast Power Coordinating Council, Dominion, Xcel Energy and Austin Energy regarding Attachment 1. These comments included request for clarification, review for redundancies, and suggested review as to relation of GOP. The EOP FYRT concurs that Attachment 1, as well as the applicability of the individual items, should be reviewed for clarification and redundancies.

Northeast Power Coordinating Council commented for the EOP FYRT to merge EOP-003-2 with EOP-001-2.1b and EOP-002-3.1, creating a single standard. The EOP FYRT will recommend that the future EOP SDT consider merging EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 into a single standard.

ACES Standards Collaborators raised the question as to why the EOP FYRT had reviewed only three of the EOP standards. A decision was made (jointly by NERC staff, the PMOS representative, and Standards Committee leadership) that because several EOP standards only recently became enforceable (or have not yet become enforceable) , the review of those standards would be deferred to gain some implementation experience to guide revising the standard. The EOP FYRT completed a review of EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

ACES Standards Collaborators also raised a concern that the review teams have not taken the Independent Expert Review Panel report into consideration during the five-year reviews. The EOP FYRT did review and take into consideration the Independent Experts’ report as it related to the EOP FYR.

Organization	Yes or No	Question 4 Comment
PacifiCorp	No	PacifiCorp appreciates the opportunity to provide input for this project and looks

Organization	Yes or No	Question 4 Comment
		forward to the next step in the process.
SPP Standards Review Group	No	
ISO/RTO Council Standards Review Committee	No	
Public Service Enterprise Group	No	
Pepco Holdings Inc	No	
Northeast Power Coordinating Council	Yes	EOP-001-2.1.b Attachment 1 should be further reviewed as it relates to the GOP in light of recent BES events, specifically Cold Weather Events. Also, add EOP-003 into the merger of EOP-001 & EOP-002. It seems to me that the justification for merging EOP-001-2.b (Emergency Operations Planning) and EOP-002-3.1 (Capacity and Energy Emergencies) into one standard (which I agree with) would also apply to including EOP-003-3 (Load Shedding Plans) in the merger. There are redundancies between EOP-001 and EOP-003 that could be eliminated. With the recommended elimination of R2, R4, R5, R6 & R7 from EOP-003-2, there would only be three requirements (R1, R3 & R8) to merge into EOP-001. Recommend that the remaining requirements (R1, R3 & R8) be merged into EOP-001.
Dominion	Yes	Dominion does not agree with adding GOP to the suggested combination of EOP-001-2.b and EOP-002-3.1. Nothing in the purpose statements of the cited standards, or the FERC directives relative to these standards indicates that reliability would be improved by expanding to these functions. It is the responsibility of the entities responsible for 'wide area' reliability (BA, RC and TOP) to insure that they request operating information necessary for them to carry out their functions. These already have the authority to require GO/GOPs provide information requested and to follow the instructions given in reliability standards IRO-001-3, TOP-001-2, and TOP-003-2.

Organization	Yes or No	Question 4 Comment
ACES Standards Collaborators	Yes	(1) We question why the team has not reviewed the other EOP standards. There are multiple requirements in the other EOP standards that would also meet Paragraph 81 criteria and should be revised. The five year review team should take this opportunity to make recommendations for the entire set of EOP standards.(2) We also recommend that the review team take the Independent Expert Review into consideration. There are several EOP modifications based on the expert's recommendations. We are concerned that the review teams are not aware of or did not consider these expert recommendations.(3) Thank you for the opportunity to comment.
Southern Company	Yes	Southern agrees with the SERC OC comments.
Idaho Power Company	Yes	Idaho Power likes the realistic look at standards for Performance-based results. The elimination of the redundant requirements makes revising these standards a worthwhile project.
Xcel Energy	Yes	Attachment 1 of EOP-001-2.1b needs to be clarified for responsibilities of all applicable entities. As written it is unclear what items BAs and TOPs should be responsible for. Additionally, Attachment 1 should be reviewed for redundancy as well. Items 1, 2, and 7 have significant overlap since the fuel supply and inventory plan probably includes fuel switching capabilities and optimizing fuel supply. Items 4, 5, 6, 9, 12, 13 all cover load curtailment or load management and are too specific. These items should be combined with general guidelines for what is expected when considering load management. Items 3, 10, and 11 also have substantial overlap.
City of Austin dba Austin Energy	Yes	Austin Energy (AE) provides the following for consideration: (1) Attachment 1 should be reviewed and revised to provide clarity as to which elements apply to the TOP and which to the BA. (2) Add clarifying language to indicate whether the "emergency plans" in R3-R6 are those "operating agreements" and "set[s] of plans" required by R1 and R2, respectively. As currently used, the term

Organization	Yes or No	Question 4 Comment
		"emergency plans" is broad and undefined.
Illinois Municipal Electric Agency	Yes	Illinois Municipal Electric Agency (IMEA) appreciates the EOP Five-Year Review Team's comprehensive review and recommendations. NERC's uniform objectives and process for review and development of high quality, results-based Reliability Standards is very encouraging. IMEA comments were limited to EOP-002 since that is the only EOP standard applicable to one of our registered functions.
SERC OC Review Group		EOP-008-1:Please consider recommending a revision of EOP-008-1 to allow planned loss of redundancy for periods greater than two weeks without requiring the construction of a tertiary facility. As unplanned losses of redundancy are allowed to extend for six months before requiring a resolution plan to be submitted to the RE [R8], it does not make sense to restrict maintenance activities to only those that can be executed in under two weeks without requiring tertiary facilities to be constructed [R3 and R4, bullet one].EOP-005-2:Consider retiring EOP-005-2, R2.1, as it appears redundant with NUC-001-2.Training:The FYRT is requested to review and eliminate any training requirements in the EOP standards (not reviewed during the 5 year process) as they are covered in the PER standards.The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Manitoba Hydro	Yes	
City of Tallahassee - Electric Utility	Yes	

END OF REPORT

Five-Year Review Template

Updated July 29, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-001-2.1b Emergency Operations Planning
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111, ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered “Yes” to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:
   Requirement R3:

   - Requirement R3.1 should be covered by EOP-001-2.1b Requirement R4 in Attachment 1 (notifications that should be included in the plan are identified). COM-001 and COM-002 are descriptive in the identification of protocols to use and, thus, adequately cover the generic reference. With the recommended revision to Attachment 1 of EOP-001-2.1b, along with COM-001 and COM-002 generic reference, Requirement R3.1 would meet Criterion B7 as redundant, as well as Criterion A (Requirement R3.1 does little, if anything, to benefit or protect the reliable operation of the BES) of Paragraph 81 and should be retired.
   - Requirement R3.2 should be covered by EOP-001-2.1b Requirement R4 in Attachment 1, which lists the actions to take during capacity situations specified in the plan. Load reduction within timelines is covered in BAL-002 Requirement R2. With the recommended revision of EOP-001 Requirement R4, Requirement R3.2 would meet Criterion B7 as redundant, as well as Criterion A (R3.1 does little, if anything, to benefit or protect the reliable operation of the BES) of Paragraph 81 and should be retired.
   - Requirement R3.4 meets Paragraph 81 Criterion B1; staffing levels are administrative in nature and would result in an increase in efficiency in the ERO compliance program (it is a simple check off during an audit). Requirement R3.4 also meets with Criterion A of Paragraph 81, as a check-off does not enhance the reliability of the BES. Requirement R3.4 should be retired as falling under Criterion B1 and Criterion A of Paragraph 81.

   Requirement 6 in its entirety:

   - Requirement R6.1 is redundant with COM-001, meeting Criterion B7 as redundant under Paragraph 81 and should be retired.
   - Requirement R6.2 speaks to an action to be taken during capacity issues that is not feasible in accomplishing. Transaction arrangements are also a commercial practice and, thus, Requirement R6.2 meets Criterion B6 of Paragraph 81 and should be retired.

- Requirement R6.3 is redundant with EOP-001-2b Requirement R4 and Attachment 1, whereby meeting Criterion B7 as redundant under Paragraph 81 and should be retired.
- Requirement R6.4 does not provide for benefit for reliability of the BES, meeting Criterion A of Paragraph 81 and should be retired.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

    a. Is this a Version 0 Reliability Standard?
    b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
    c. Are the requirements consistent with the purpose of the Reliability Standard?

    ☒ Yes

    ☐ No

    Please summarize your assessment:
    The 2009-03 Emergency Operations Five-Year Review Team (EOP FYRT) recommends that EOP-001-2.b and EOP-002-3.1 be revised and merged into a single standard identifying clearly and separately the Transmission Operator, Generation Operator and Reliability Coordinator issues as they relate to the BA and TOP (to address Paragraph 548 of Order 693) and how it needs to be planned and implemented for on the BES by the specific functional entities.

    - Requirement R1 needs clarity provided as to what an operating agreement constitutes, and adjust the VSL to reflect current interpretations with the number of agreements needed. Requirement R1 must also account for current interpretations found in the Appendix and other interpretations.
    - Requirement R2 needs clarity provided, as instructed by the Commission, on the ambiguity of the EOP standards as they relate to the responsibilities of the Transmission Operator and Balancing Authority.
    - Requirement R5, the need to share emergency plans with neighboring Transmission Operators and Balancing Authorities, should be removed as an administrative burden (identified in P81); however, the remaining language of the requirement should be affirmed.
    - Review is recommended for Attachment 1 as it relates to the GOP in light of recent BES events (Cold Weather Event).

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☒ Yes

☐ No

Please explain:
Appendix 1 attempts to define what a remote Balancing Authority is and should be addressed in future revisions of the Standard

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

   Additional measures must be provided with this standard. There are no performance measures. There are no VRFs with this standard. Requirement R1, once recommended clarity is provided as to what an operating agreement constitutes, adjustment to the VSL will be necessary to reflect current interpretations with the number of agreements needed.

☐ Yes

☒ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

☐ Yes

☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

☐ Yes

☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

☒ Yes
☐ No

Guiding Questions:

If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE – Requirement R1, R2, R5 and Attachment 1

☒ RETIRE – Requirements R3.1, R3.2, R3.4, R6.1, R6.2, R6.3, R6.4

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE – Requirements R1, R2, R5 and Attachment 1

☒ RETIRE – Requirements R3.1, R3.2, R3.4; Requirement R6 in its entirety; R6.1, R6.2, R6.3, R6.4

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

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[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Five-Year Review Template

Updated July 29, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-002-3.1 Capacity and Energy Emergencies
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111,ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   - Requirement R1 is redundant with IRO-001 and PER-001-2 and should be retired under Criterion B7 of Paragraph 81.
   - Requirement R6 is redundant with BAL-002-1a and should be retired under Criterion B7 of Paragraph 81.
   - Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR, and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired. Due to the retirement of R9, LSE applicability should be removed in the standard.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

Please summarize your assessment:
The EOP FYRT recommends that EOP-001-2b and EOP-002-3.1 be revised and merged into a single standard to address redundancy in the stating that a plan should be implemented. Both standards are different enough that those requirements not identified in retirement recommendations under Paragraph 81 should be retained.

Requirement R8 and Attachment 1 have several issues regarding applicability to different functions and should be revised to eliminate discrepancies and for clarity. Attachment 1 needs to be reviewed for consistency with IRO and TOP standards. The EOP FYRT recommends review of the uniqueness as it relates to ERCOT and similarly situated BAs. The EOP FYRT recommends the future EOP SDT address the directive in Paragraph 573 of Order 693.

The EOP FYRT further recommends a language change in Requirement R2, replacing "interconnected system" with "Bulk Electric System." Requirements R3 and R4 need to be reviewed by the future EOP SDT to further define the word "emergency" (as Capacity Emergency, Emergency, and Energy Emergency are already NERC defined terms). The EOP FYRT recommends the following sentence in Requirement R5 to be struck: "Such unilateral adjustment may overload transmission facilities."

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes

☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

☒ Yes

☐ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or

consistency with other Reliability Standards? If you answered “Yes,” please describe the changes needed to achieve formatting and language consistency:

☐ Yes

☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered “Yes,” please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised: Requirement R9 (recommended for retirement under Paragraph 81) the TSP now has the ability to change the Transmission priority, which is in turn reflected in the IDC.

☒ Yes

☐ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

☒ Yes
☐ No

Guiding Questions:

If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE (and merge with EOP-001-2b)

☒ RETIRE – Requirements R1, R6 and R9 in its entirety.

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE (and merge with EOP-001-2b); Requirement R2, replacing "interconnected system" with "Bulk Electric System;" language revision in Requirement R2; Requirements R3 and R4 need to be reviewed by the future EOP SDT to further define the word "emergency" (as Capacity Emergency, Emergency, and Energy Emergency are already NERC defined terms); Requirement R5, strike "Such unilateral adjustment may overload transmission facilities."

☒ RETIRE – Requirements R1, R6, and R9 in its entirety. Due to the retirement of R9, LSE applicability should be removed in the standard.

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

NERC

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Five-Year Review Template

Updated July 29, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-003-2 Load Shedding Plans
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111, ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   - Requirements R5 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R5 speaks to shedding loads in steps; that same process will be done in Requirement R1. Requirement R5 should be retired under Criterion B7 of Paragraph 81.
   - Requirements R6 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R6 speaks of two events that must be valid to tell the BA or TOP to shed more load, but overall the action of shedding load to meet insufficient generation is the same as stated in Requirement R1. Requirement R6 should be retired under Criterion B7 of Paragraph 81.
   - EOP-003-2– Recommend that Requirements R2, R4 and R7 be moved to PRC-010-0 or otherwise addressed during Project 2008-02 – Undervoltage Load Shedding.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

Please summarize your assessment:
The EOP FYRT team believes that Requirements R2, R4 and R7 should be coordinated with the revision of PRC-010 (Project 2008-02 Undervoltage Load Shedding) for inclusion in that standard. This is consistent with the review that was done for automatic underfrequency requirements and should also be performed for automatic undervoltage requirements.

Based on the recommendations received during the comment period, EOP FYRT further recommends R1 and R8 be considered to be combined. The EOP FYRT also received comments that EOP-003-2 should be combined with EOP-001-2.1b and EOP-002-3.1, and the EOP FYRT recommends this be evaluated in the SAR. In addition, the EOP FYRT recommends that the future EOP SDT evaluate the separation of the functional entity capabilities of the BA and the TOP responsibilities.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

   ☐ Yes

   ☒ No

   Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered “No,” please identify which elements require revision, and why:

   The Measures and Data retention should be reviewed and updated

   ☐ Yes

   ☒ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered “Yes,” please describe the changes needed to achieve formatting and language consistency:

   ☐ Yes

   ☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☐ Yes

   ☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation
The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE – Retire Requirements R5, R6, R2, R4 and R7 and address directives in Paragraphs 595 and 603 of Order 693

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*: See responses to questions 1, 2, and 4 above.

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE - Retire Requirements R5, R6, R2, R4 and R7 and address directives in Paragraphs 595 and 603 or Order 693; recommend for consideration Requirements R1 and R8 be combined; consider combining EOP-003-2 with EOP-001-2.1b and EOP-002-3.1; evaluate the separation of the functional entity capabilities of the BA and TOP responsibilities.

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Emergency Operations (EOP-001-2.1b, EOP-002-3.1, EOP-003-2)		
Date Submitted:	October 17, 2013		
SAR Requester Information			
Name:	David McRee, Chair EOP Five-Year Review Team (FYRT)		
Organization:	Duke Energy		
Telephone:	(704) 382-9841	E-mail:	David.McRee@duke-energy.com
SAR Type (Check as many as applicable)			
☐ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
This SAR will address the Five-Year Review recommendations for these standards.
Purpose or Goal (How does this request propose to address the problem described above?):
To improve the quality, relevance, and clarity of the standards. Also bring the standards into the Results Based Standards format.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
To increase the effectiveness of the three standards in their ability to ensure reliability of the BES.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The EOP SDT will implement recommendations of the EOP FYRT, which includes consideration of industry comments and the report from the Industry Expert Review Panel. Recommendations for consideration are: • Modify the requirements and attachments to improve their clarity and measurability, while removing ambiguity • Move, consolidate, and/or streamline requirements • Eliminate requirements based on P81 criteria To ensure a seamless transition from the EOP FYRT to the future EOP SDT, the EOP FYRT recommends the inclusion of interested EOP FYRT members to participate on the EOP SDT. In addition, the EOP FYRT should provide a high-level overview of their recommendations as a formal kick-off to the future EOP SDT meetings.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
See the attached Five-Year Review templates of the three standards, consideration of comments, issues and directives list, redlined standards (reflecting deletions), and the EOP FYRT's consideration of the IERP recommendations on the three standards.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☒ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.
☒ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and

Reliability Functions	
	supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.
☒ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐ Distribution Provider	Delivers electrical energy to the End-use customer.
☐ Generator Owner	Owns and maintains generation facilities.
☒ Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐ Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐ Market Operator	Interface point for reliability functions with commercial functions.
☒ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner

Reliability and Market Interface Principles	
	to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards	
Standard No.	Explanation
BAL-001-0.1a	Real Power Balancing Control Performance
BAL-002-01	Disturbance control standard
BAL-002-WECC	Regional Contingency Reserve standard

Related Standards	
PRC-010-0	Planning for Undervoltage Load shedding
PER-005-1	Training

Related SARs	
SAR ID	Explanation
	None other than those for projects already active, including Project 2008-02

Regional Variances	
Region	Explanation
ERCOT	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Five Year Review Team Recommendations posted for informal comment period (August 6-September 19, 2013).
2. Developed SAR, proposed revisions to the standard and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).

Description of Current Draft

This is the first draft of the proposed standard presented to the NERC Standards Committee for authorization to ~~moving~~ move the SAR forward to standard development. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	
45-day Formal Comment Period with Parallel Initial Ballot	
30-day Formal Comment Period with Parallel Successive Ballot	
Recirculation ballot	
BOT adoption	

Effective Dates

First day of the second calendar quarter beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking
0	February 8, 2005	Adopted by the Board of Trustees	New
0	April 1, 2005	Effective Date	New
0	August 8, 2005	Removed "Proposed" from Effective Date	Errata
1	October 17, 2008	Deleted R2 Replaced Levels of Non-compliance with the February 28, 2008 BOT approved Violation Severity Levels Corrected typographical errors in BOT approved version of VSLs	Revised IROL Project
2	August 5, 2009	Removed R2.4 as redundant with EOP-005-2 Requirement R1 for the Transmission Operator; the Balancing Authority does not need a restoration plan.	Revised Project 2006-03
2	August 5, 2009	Adopted by NERC Board of Trustees: August 5, 2009	Revised
2	March 17, 2011	FERC Order issued approving EOP-001-2 (Clarification issued on July 13, 2011)	Revised
2b	November 4, 2010	Adopted by NERC Board of Trustees	Project 2008-09 - Interpretation of Requirement R1
2b	November 4, 2010	Adopted by NERC Board of Trustees	Project 2009-28 - Interpretation of Requirement R2.2
2b	December 15, 2011	FERC Order issued approving Interpretation of R1 and R2.2 (Order effective December 15, 2011)	Project 2008-09 - Interpretation of Requirement R1 and

			Project 2009-28 - Interpretation of Requirement R2.2
2.1b	**March 8, 2012**	**Errata adopted by Standards Committee; (changed title and references to Attachment 1 to omit inclusion of version numbers and corrected references in Appendix 1 Question 4 from "EOP-001-0" to "EOP-001-2")**	**Errata**
2.1b	**September 13, 2012**	**FERC approved**	**Errata**
3	**TBD**	**TBD**	**Five Year Review team**

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Emergency Operations Planning**
2. **Number:** EOP-001-3~~2.1b~~
3. **Purpose:** Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authorities

   4.1.2 Transmission Operators
5. **Background:**

   Text

B. Requirements and Measures

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities. *[Violation Risk Factor: High] [Time Horizon: TBD]*

Rationale for R1:

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

R2. Each Transmission Operator and Balancing Authority shall: *[Violation Risk Factor: Medium] [Time Horizon: TBD]*

Rationale for R2:

2.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

2.3. Develop, maintain, and implement a set of plans for load shedding.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include: *[Violation Risk Factor: Medium] [Time Horizon: TBD]*

Rationale for R3:

3.1. ~~Communications protocols to be used during emergencies~~.

3.2. ~~A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions~~.

3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

3.4. ~~Staffing levels for the emergency~~.

M3. Text

R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan. *[Violation Risk Factor: Medium] [Time Horizon: TBD]*

Rationale for R4:

M4. Text

R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities. *[Violation Risk Factor: Medium] [Time Horizon: TBD]*

Rationale for R5:

M5. Text

~~**R6.** The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable: *[Violation Risk Factor: Medium] [Time Horizon: TBD]*~~

Rationale for R6:

~~**6.1.** The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.~~

~~**6.2.** The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.~~

~~**6.3.** The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)~~

~~**6.4.** The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.~~

M6. Text

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, R4, and R5 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R3 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1		High	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for less than 25% of the adjacent BAs. Or less than 25% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 25% to 50% of the adjacent BAs. Or 25 to 50% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 50% to 75% of the adjacent BAs. Or 50% to 75% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 75% or more of the adjacent BAs. Or more than 75% of those agreements do not contain provisions for emergency assistance.
R2		Medium	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	N/A	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.
R2.1			The Transmission Operator or Balancing Authority’s emergency plans to mitigate insufficient generating capacity are missing minor details or minor program/procedural	The Transmission Operator or Balancing Authority's has demonstrated the existence of emergency plans to mitigate insufficient generating capacity	The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity emergency plans are neither maintained nor	The Transmission Operator or Balancing Authority has failed to develop emergency mitigation plans for insufficient generating capacity.

			elements.	emergency plans but the plans are not maintained.	implemented.	
R2.2			The Transmission Operator or Balancing Authority’s plans to mitigate transmission system emergencies are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of transmission system emergency plans but are not maintained.	The Transmission Operator or Balancing Authority's transmission system emergency plans are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement operating emergency mitigation plans for emergencies on the transmission system.
R2.3			The Transmission Operator or Balancing Authority’s load shedding plans are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of load shedding plans but are not maintained.	The Transmission Operator or Balancing Authority's load shedding plans are partially compliant with the requirement but are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement load shedding plans.
R3		Medium	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with all four (4) of the sub-components.

~~R3.1~~			~~The Transmission Operator or Balancing Authority's communication protocols included in the emergency plan are missing minor program/procedural elements.~~	~~N/A~~	~~N/A~~	~~The Transmission Operator or Balancing Authority has failed to include communication protocols in its emergency plans to mitigate operating emergencies.~~
~~R3.2~~			~~The Transmission Operator or Balancing Authority's list of controlling actions has resulted in meeting the intent of the requirement but is missing minor program/procedural elements.~~	~~N/A~~	~~The Transmission Operator or Balancing Authority provided a list of controlling actions, however the actions fail to resolve the emergency within NERC-established timelines.~~	~~The Transmission Operator or Balancing Authority has failed to provide a list of controlling actions to resolve the emergency.~~
R3.3			The Transmission Operator or Balancing Authority has demonstrated coordination with Transmission Operators and Balancing Authorities but is missing minor program/procedural elements.	N/A	N/A	The Transmission Operator or Balancing Authority has failed to demonstrate the tasks to be coordinated with adjacent Transmission Operator and Balancing Authorities as directed by the requirement.

~~R3.4~~			~~The Transmission Operator or Balancing Authority's emergency plan does not include staffing levels for the emergency~~	~~N/A~~	~~N/A~~	~~N/A~~
R4		Medium	The Transmission Operator and Balancing Authority's emergency plan has complied with 90% or more of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with 70% to 90% of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with between 50% to 70% of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with 50% or less of the number of sub-components
R5		Medium	The Transmission Operator and Balancing Authority is missing minor program/procedural elements.	The Transmission Operator and Balancing Authority has failed to annually review one of it's emergency plans	The Transmission Operator and Balancing Authority has failed to annually review two of its emergency plans or communicate with one of it's neighboring Balancing Authorities.	The Transmission Operator and Balancing Authority has failed to annually review and/or communicate any emergency plans with its Reliability Coordinator, neighboring Transmission Operators or Balancing Authorities.
~~R6~~		~~Medium~~	~~The Transmission Operator and/or the Balancing Authority failed to comply with one (1) of the sub-components.~~	~~The Transmission Operator and/or the Balancing Authority failed to comply with two (2) of the sub-components.~~	~~The Transmission Operator and/or the Balancing Authority has failed to comply with three (3) of the sub-components.~~	~~The Transmission Operator and/or the Balancing Authority has failed to comply with four (4) or more of the sub-~~

						~~components.~~
~~R6.1~~			~~The Transmission Operator or Balancing Authority has failed to establish and maintain reliable communication between interconnected systems.~~	~~N/A~~	~~N/A~~	~~N/A~~
~~R6.2~~			~~The Transmission Operator or Balancing Authority has failed to arrange new interchange agreements to provide for emergency capacity or energy transfers with required entities when existing agreements could not be used.~~	~~N/A~~	~~N/A~~	~~N/A~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Attachment 1-EOP-001

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.

2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.

3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.

4. System energy use — The reduction of the system's own energy use to a minimum.

5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.

6. Load management — Implementation of load management and voltage reductions, if appropriate.

7. Optimize fuel supply — The operation of all generating sources to optimize the availability.

8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.

9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.

10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.

11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.

12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.

13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

Appendix 1

Requirement Number and Text of Requirement
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
Questions:
1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition? 2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance? 3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement? 4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-2, Requirement 1?
Responses:
1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe

the conditions under which the emergency energy will be delivered to the responsible Balancing Authority. 2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections. 3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities. 4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-2.

Appendix 2

Requirement Number and Text of Requirement
R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Questions:
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Questions:

The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001."

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Five Year Review Tam Recommendations posted for informal comment period (August 6-September 19, 2013).
2. Developed SAR, proposed revisions to the standard and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).

Description of Current Draft

This is the first draft of the proposed standard presented to the NERC Standards Committee for authorization ~~moving~~ to move the SAR forward to standard development. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	
45-day Formal Comment Period with Parallel Initial Ballot	
30-day Formal Comment Period with Parallel Successive Ballot	
Recirculation ballot	
BOT adoption	

Effective Dates

First day of the second calendar quarter beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking
0	**April 1, 2005**	**Effective Date**	**New**
0	**August 8, 2005**	**Removed "Proposed" from Effective Date**	**Errata**
1	**September 19, 2006**	**Changes R7. to refer to "Requirement 6" instead of "Requirement 7"**	**Errata**
2	**November 1, 2006**	**Adopted by Board of Trustees**	**Revised**
2	**November 1, 2006**	**Corrected numbering in Section A.4. "Applicability."**	**Errata**
2	**October 1, 2007**	**Added to Section 1 inadvertently omitted "4.3. Load-Serving Entities**	**Errata**
2.1	**October 29, 2008**	**BOT adopted errata changes; updated version number to "2.1"**	**Errata**
2.1	**May 13, 2009**	**FERC Approved**	**Revised**
3	**June 4, 2010**	**Modified to address Order No. 693 Directives contained in paragraphs 582.**	**Revised.**
3	**August 5, 2010**	Adopted by NERC Board of Trustees	**New**
3.1	**March 8, 2012**	Errata adopted by Standards Committee; (Updated title of Attachment 1 and changed references to Attachment 1 throughout Standard from "Attachment 1-EOP-002-0 Energy Emergency Alert Levels" to "Attachment 1-EOP-002 Energy Emergency Alerts". Removed parenthetical in Requirement R9 referencing a retired Attachment in IRO-006)	**Errata**
3.1	**September 13, 2012**	FERC Approved	**Errata**
4	**TBD**	TBD	**Five Year Review**

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Capacity and Energy Emergencies**
2. **Number:** EOP-002-~~4~~3.~~1~~
3. **Purpose:** To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authorities

   4.1.2 Reliability Coordinators

   ~~**4.1.3** Load-Serving Entities~~
5. **Background:**

   Text

B. Requirements and Measures

~~**R1.** Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies. *[Violation Risk Factor: High] [Time Horizon: TBD]*~~

Rationale for R1:

~~**M1.** Text~~

~~**R2.**~~**R1.** Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan to reduce risks to the ~~interconnected~~ Bulk Electric ~~system~~System. *[Violation Risk Factor: High] [Time Horizon: TBD]*

Rationale for R2:

~~**M2.**~~**M1.** Text

~~R3.~~R2. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities. *[Violation Risk Factor: High] [Time Horizon: TBD]*

Rationale for R3:

~~M3.~~M2. Text

~~R4.~~R3. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load. *[Violation Risk Factor: High] [Time Horizon: TBD*

Rationale for R4:

~~M4.~~M3. Text

~~R5.~~R4. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. ~~Such unilateral adjustment may overload transmission facilities.~~ *[Violation Risk Factor: High] [Time Horizon: TBD]*

Rationale for R5:

~~M5.~~M4. Text

~~**R6.** If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so.~~

~~These remedies include, but are not limited to: *[Violation Risk Factor: High] [Time Horizon: TBD]*~~

Rationale for R6:

~~**6.1.** Loading all available generating capacity.~~

~~**6.2.** Deploying all available operating reserve.~~

~~**6.3.** Interrupting interruptible load and exports.~~

~~**6.4.** Requesting emergency assistance from other Balancing Authorities.~~

~~**6.5.** Declaring an Energy Emergency through its Reliability Coordinator; and~~

~~**6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.~~

~~**M6.** Text~~

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~~R7.~~R5. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards,~~Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition~~, the Balancing Authority shall: *[Violation Risk Factor: High] [Time Horizon: TBD]*

Rationale for R7:

~~7.1.~~5.1. R7.1. Manually shed firm load without delay to return its ACE to zero; and

~~7.2.~~5.2. R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."

~~M7.~~M5. Text

~~R8.~~R6. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required. *[Violation Risk Factor: High] [Time Horizon: TBD]*

Rationale for R9:

~~M8.~~M6. Text

~~**R9.** When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff: *[Violation Risk Factor: High] [Time Horizon: TBD]*~~

Rationale for R9:

~~**9.1.** The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."~~

~~**9.2.** The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.~~

~~**9.3.** The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.~~

~~**9.4.** The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.~~

~~M9.~~M7. Text

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, R4, and R5 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R3 for the most recent three calendar months plus the current month.

- If a Balancing Authority or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

1.3. The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records. **Compliance Monitoring and Assessment Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
~~**R1**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority or Reliability Coordinator does not have responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area OR The Balancing Authority or Reliability Coordinator did not exercise its authority to alleviate capacity and energy emergencies.~~
R2		**High**	N/A	N/A	N/A	The Balancing Authority did not implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.
R3		**High**	N/A	N/A	The Balancing Authority communicated its current and future system conditions to its Reliability Coordinator but did not communicate to one or more of its neighboring Balancing Authorities.	The Balancing Authority has failed to communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.
R4		**High**	N/A	N/A	N/A	The Balancing Authority has failed to perform the necessary actions as required and stated in the

						requirement.
R5		**High**	N/A	N/A	The Balancing Authority used the assistance provided by the Interconnection's frequency bias for more time than needed to implement corrective actions.	The Balancing Authority used the assistance provided by the Interconnection's frequency bias for more time than needed to implement corrective actions and unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes.
~~**R6**~~		~~**High**~~	~~The Balancing Authority failed to comply with one of the sub-components.~~	~~The Balancing Authority failed to comply with 2 of the sub-components.~~	~~The Balancing Authority failed to comply with 3 of the sub-components.~~	~~The Balancing Authority failed to comply with more than 3 of the sub-components.~~
~~**6.1**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority did not use all available generating capacity.~~
~~**6.2**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority did not deploy all of its available operating reserve.~~
~~**6.3**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority did not interrupt interruptible load and exports.~~
~~**6.4**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority did not request emergency assistance from other Balancing Authorities.~~
~~**6.5**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority did not declare an Energy~~

						~~Emergency through its Reliability Coordinator.~~
~~**6.6**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority did not implement one or more of the procedures stated in the requirement.~~
R7		**High**	N/A	N/A	The Balancing Authority has met only one of the two requirements	The Balancing Authority has not met either of the two requirements
7.1		**High**	N/A	N/A	N/A	The Balancing Authority did not manually shed firm load without delay to return it's ACE to zero.
7.2		**High**	The Balancing Authority's implementation of an Energy Emergency Alert has missed minor program/procedural elements in Attachment 1-EOP-002-0.	N/A	N/A	The Balancing Authority has failed to meet one or more of the requirements of Attachment 1-EOP-002-0.
R8		**High**	The Reliability Coordinator's implementation of an Energy Emergency Alert has missed minor program/procedural elements in Attachment 1-EOP-002-0.	N/A	N/A	The Reliability Coordinator has failed to meet one or more of the requirements of Attachment 1-EOP-002-0.
~~**R9**~~		~~**High**~~	~~The Reliability Coordinator failed to comply with one (1) of the sub-components.~~	~~The Reliability Coordinator failed to comply with two (2) of the sub-components.~~	~~The Reliability Coordinator has failed to comply with three (3) of the sub-components.~~	~~The Reliability Coordinator has failed to comply with all four (4) of the sub-components.~~
~~**9.1**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Load-Serving Entity failed to request its Reliability Coordinator to initiate an Energy~~

						~~Emergency Alert.~~
~~**9.2**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator has failed to report to NERC as directed in the requirement.~~
~~**9.3**~~		~~**Lower**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator failed to use EEA 1 to forecast the change of the priority of transmission service as directed in the requirement.~~
~~**9.4**~~		~~**Lower**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator failed to use EEA 2 to announce the change of the priority of transmission service as directed in the requirement.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Attachment 1-EOP-002
Energy Emergency Alerts

Introduction
This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. Initiation by Reliability Coordinator. An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

1.1. Situations for initiating alert. An Energy Emergency Alert may be initiated for the following reasons:

- When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
- The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. Notification. A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction
To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining energy

emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **Alert 1 — All available resources in use.**

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **Alert 2 — Load management procedures in effect**.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
  - Public appeals to reduce demand.
  - Voltage reduction.
  - Interruption of non-firm end use loads in accordance with applicable contracts[1].
  - Demand-side management.
  - Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers.

[1] For emergency, not economic, reasons.

Application Guidelines

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

2.4 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 Notification of ATC adjustments. Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.

2.4.2 Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.

2.4.3 Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.

2.4.4 Initiating inquiries on reevaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.

2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:

2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.

2.6.4 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

Application Guidelines

3. Alert 3 — Firm load interruption imminent or in progress.

Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2. The Reliability Coordinators and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Energy Deficient Entity obligations. The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 Notification of other parties. Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. **Alert 0 - Termination.** When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

   4.1. Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

Entity experiencing energy deficiency (if different from Balancing Authority):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other Balancing Authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

Application Guidelines

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. **All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.**

2. **All firm and nonfirm purchases were made regardless of cost.**

3. **All nonfirm sales were recalled within provisions of the sale agreement.**

4. **Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.**

5. **Available load reduction programs were exercised (public appeals, voltage reductions, etc.).**

6. **Operating Reserves being utilized.**

Comments:

Reported By: **Organization:**

Title:

Application Guidelines

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Five Year Review Tam Recommendations posted for informal comment period (August 6-September 19, 2013).
2. Developed SAR, proposed revisions to the standard and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).

Description of Current Draft

This is the first draft of the proposed standard presented to the NERC Standards Committee for authorization ~~moving~~ to move the SAR forward to standard development. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	
45-day Formal Comment Period with Parallel Initial Ballot	
30-day Formal Comment Period with Parallel Successive Ballot	
Recirculation ballot	
BOT adoption	

Effective Dates

First day of the second calendar quarter beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking
0	**April 1, 2005**	**Effective Date**	**New**
0	**August 8, 2005**	**Removed "Proposed" from Effective Date**	**Errata**
1	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 4, 2010	Adopted by Board of Trustees; Modified R4, R5, R6 and associated VSLs for R2, R4, and R7 to clarify that the requirements don't apply to automatic underfrequency load shedding.	Revised to eliminate redundancies with PRC-006-1
2	May 7, 2012	FERC Order issued approving EOP-003-2 (approval becomes effective July 10, 2012)	
3	TBD	TBD	Five Year Review

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Term: definition.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Load Shedding Plans**
2. **Number:** EOP-003-~~2~~3
3. **Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Transmission Operator
5. **Background:**

   Text

B. Requirements and Measures

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection. *[Violation Risk Factor: High] [Time Horizon:]*

Rationale for R1:

M1. Text

~~**R2.** Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required. *[Violation Risk Factor: High] [Time Horizon:]*~~

Rationale for R2:

~~**M2.** Each Transmission Operator that has or directs the deployment of undervoltage load shedding facilities, shall have and provide upon request, its automatic load shedding plans. (Requirement 2)~~

~~**R3.**~~**R2.** Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities. *[Violation Risk Factor: High] [Time Horizon:]*

Rationale for R3:

~~**M3.**~~**M2.** Text

~~**R4.** A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels. *[Violation Risk Factor: High] [Time Horizon:]*~~

Rationale for R4:

~~**M4.** Text~~

~~**R5.** A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown. *[Violation Risk Factor: High] [Time Horizon:]*~~

Rationale for R5:

~~**M5.** Text~~

~~**R6.** After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load. *[Violation Risk Factor: High] [Time Horizon:]*~~

Rationale for R6:

~~**M6.** Text~~

~~**R7.** The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions. *[Violation Risk Factor: High] [Time Horizon:]*~~

Rationale for R7:

~~**M7.** Text~~

~~R8.~~R3. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency. *[Violation Risk Factor: High] [Time Horizon:]*

Rationale for R8:

~~M8.~~M3. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

- If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.
- Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.
- The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1		**High**	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
~~**R2**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the requirement.~~
R3		**High**	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
~~**R4**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or~~

						~~power flow levels) listed in the requirement.~~
~~R5~~		~~High~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator or Balancing Authority failed to implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.~~
~~R6~~		~~High~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.~~
~~R7~~		~~High~~	~~The Transmission Operator did not coordinate automatic undervoltage load~~	~~The Transmission Operator did not coordinate automatic undervoltage load~~	~~The Transmission Operator did not coordinate automatic undervoltage load~~	~~The Transmission Operator did not coordinate automatic undervoltage load~~

			~~shedding with 5% or less of the types of automatic actions described in the Requirement.~~	~~shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.~~	~~shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.~~	~~shedding with more than 15% of the types of automatic actions described in the Requirement.~~
R8		**High**	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Directive Summary	Document Reference	Publication Date	Reference	Standard	Full Text
S- Ref 10063 - We direct the ERO to determine the optimum number of continent-wide system states and their attributes and to modify the Reliability Standards through the Reliability Standards development process to accomplish this objective.	Order 693	16-Mar-07	Para 561	EOP-001	561. As we noted in the NOPR, some control areas define and effectively use more than the "normal," "alert" and "emergency" system states included in the Blackout Report recommendation. We proposed that the ERO determine the optimum number of system states to be employed continent-wide and to consider the addition of the restoration state. Accordingly, we direct the ERO to determine the optimum number of continent-wide system states and their attributes and to modify the Reliability Standard through the Reliability Standards development process to accomplish this objective.
S- Ref 10064 - Consider a pilot program (field test) for the system states proposal.	Order 693	16-Mar-07	Para 562	EOP-001	562. Further, we agree with ISO-NE that the proposed modification should be field tested and that policies and procedure be put in place, including operator training, before any processes for continent-wide system states are implemented. Such testing will help assure that all applicable entities and their personnel understand how the terms will be used and will allow operators to train staff to make any necessary changes to their policies and procedures. We direct the ERO to consider such a pilot program as it modifies EOP-001-0 through the Reliability Standards development process.
S- Ref 10065 - Clarifies that the actual emergency plan elements, and not the for consideration elements of Attachment 1, should be the basis for compliance.	Order 693	16-Mar-07	Para 565	EOP-001	565. The Commission agrees with ISO-NE that the Reliability Standard should be clarified to indicate that the actual emergency plan elements, and not the "for consideration" elements of Attachment 1, should be the basis for compliance. However, all of the elements should be considered when the emergency plan is put together.
S- Ref 10066 - Address emergencies resulting not only from insufficient generation but also insufficient transmission capability, particularly as it affects the implement of the capacity and energy emergency plan.	Order 693	16-Mar-07	Para 571	EOP-002	571. As we stated in the NOPR, neither EOP-002-2 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies. The Commission agrees with MRO that "insufficient transmission capability" could be due to various causes. The ERO should examine whether to clarify this term in the Reliability Standards development process.
S- Ref 10067 - Include all technically feasible resource options, including demand response and generation resources	Order 693	16-Mar-07	Para 573	EOP-002	573. The Commission agrees with FirstEnergy that for demand-side resources to qualify as another tool for balancing authorities to use in meeting control performance and disturbance control Reliabilty Standards, they must meet comparable technical performance requirements as generation resource options. In response to comments from Comverge and APPA, the Commission believes that curtailable loads are adequately addressed in Requirement R6 of the Reliability Standard but that demand response is not covered. Demand response covers considerably more resources than interruptible load. Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements.
S- Ref 10072 - Develop specific minimum load shedding capability that should be provided .. based on overarching nationwide criteria that take into account system characteristics.	Order 693	16-Mar-07	Para 595	EOP-003	595. The Commission concludes that the Reliability Standard needs to be modified to ensure that adequate load shedding capabilities are provided so that system operators have an effective operating measure of last resort to contain system emergencies and prevent cascading. The Commission recognizes that the amount of load shedding capability required is dependent on system characteristics and therefore it may not be feasible to have a uniform nationwide load shedding capability. This, however, does not preclude a uniform nationwide criterion on the methodology for establishing load shedding capability that would specify the minimum amount of load shedding capability that should be provided based on system characteristics and conditions and the maximum amount of delay before load shedding can be implemented. The Commission directs the ERO to address the minimum load and maximum time concerns of the Commission through the Reliability Standards development process. We suggest that a review of industry best practices would be useful in developing nationwide critera.

S- Ref 10073 - Require periodic drills of simulated load shedding.	Order 693	16-Mar-07	Para 597	EOP-003	597. As suggested by California PUC, periodic drills of simulated load shedding should involve all participants required to ensure successful implementation of load shedding plans. As such, the drills should extend beyond system operators to distribution operators and LSEs. The Reliability Standard should require periodic drills by entities subject to section 215, and require those entities to seek participation by other entities. The drills should test the readiness and functionality of the load shedding plans, including, at times, the actual deployment of personnel. Therefore the Commission disagrees with FirstEnergy that the requirement for periodic drills of simulated load shedding should be incorporated into the new PER-005-0 Reliability Standard that is currently being drafted to address operator training.
S- Ref 10074 - Consider comments from APPA in the standards development process.	Order 693	16-Mar-07	Para 601	EOP-003	
548. Further we agree with SoCal Edison that clear direction is needed on which requirements should be exclusive to transmission operators and balancing authorities with the reliability coordinator being responsible for incorporating this information into its overarching plan. Accordingly, the Commission finds the reliability coordinator is a necessary entity under EOP-001-0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity. In addition, the ERO should consider SoCal Edison's suggestion in the ERO's Reliability Standards development process.	Order 693	16-Mar-07	Para 548	EOP-001	548. Further we agree with SoCal Edison that clear direction is needed on which requirements should be exclusive to transmission operators and balancing authorities with the reliability coordinator being responsible for incorporating this information into its overarching plan. Accordingly, the Commission finds the reliability coordinator is a necessary entity under EOP-001-0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity. In addition, the ERO should consider SoCal Edison's suggestion in the ERO's Reliability Standards development process.

FYRT Notes

NOTE: The FYRT suggested revisions to Attachment 1 that may address this directive.

NOTE: This language is no longer in the standard.

NOTE: See Para 572 for more specific recommendations.

NOTE: May want to perfrorm a data request to see what ndustry is doing today and attempt to develop a "floor". See also Para 603.

NOTE: See para 603 also.

APPA Comments are in Paragraph 598: "In addition, APPA states that NERC should consider requiring balancing authorities and transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners."

Associated Standard	Associated Project	Source
EOP-001	2009-03	Version 1 Team
EOP-001	2009-03	Version 1 Team
EOP-001	2009-03	Version 1 Team
EOP-001	2009-03	VRFs Team
EOP-003	2009-03	Version 0 Team
EOP-003	2009-03	Version 0 Team
EOP-003	2009-03	Version 0 Team
EOP-003	2009-03	VRFs Team
EOP-003	2009-03	VRFs Team
EOP-001	2009-03	NERC Audit Observation Team
EOP-002	2009-03	NERC Audit Observation Team
EOP-003	2009-03	NERC Audit Observation Team
EOP-001	2009-03	Real-time Best Practices Standards Study Group
EOP-003	2009-03	Real-time Best Practices Standards Study Group

EOP-001	2009-03	Frank Gaffney (FMPA)
EOP-001	2009-03	Frank Gaffney (FMPA)
EOP-001	2009-03	Frank Gaffney (FMPA)
EOP-001	2009-03	Frank Gaffney (FMPA)

EOP-001	2009-03	Frank Gaffney (FMPA)

Issue Description
Combine R4 & R5
Revise R5
Measures are really data retention requirements
R1 primarily administrative
Move implementation requirements
Re-state purpose
Add UVLS
R4 Needs clarification
R6 - Failure to shed load in this condition can inhibit restoration.
BA shall have operating agreements with adjacent BA's that shall, at a minimum, contain provisions for emeergency assistance, including provision to obtain emergency assistanc from remote BA's. What is "emergency assistance"? Does a reserve sharing grou
This NERC standard references the RC or BA to implement it's capacity and energy plans. The RC does not have capacity and energy plans.
The purpose of the standard states that the BA and TOP must have the capability and authority to shed load. What do we mean by capability? Is directing someone to take action to open breakers the same thing as capability?
Establish document plans and procedures for conservative operations
Provide the location, Real-time status, and MWs of Load available to be shed.

The NERC Glossary of terms defines a BA as: "The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time." In oth
The NERC Glossary of terms defines a TOP as: "(t)he entity responsible for the reliability of its 'local' transmission system, and that operates or directs the operations of the transmission facilities." With this definition in mind, why is the TOP made r
Requirement R4 (and by reference Attachment 1-EOP-001-0) is applicable to both the Transmission Operator and Balancing Authority but includes items that are not applicable to the TOP and are only applicable to the BA, e.g., why is a TOP responsible for fu
With regard to requirement R2, why is the BA responsible for Under Frequency Load Shedding (UFLS) when PRC-006-0 and PRC-007-0 make it the responsibility of the Regional Entities, the TOPs, the Distribution Providers and the LSEs? Why is the BA responsibl

Requirement R2 of EOP-003-1 states: Each Transmission Operator and Balancing Authority shall establish plans for automatic load shedding for underfrequency or undervoltage conditions. The standards drafting team for Project 2007-01 Underfequency Load She

EOP Five-Year Review Team Consideration of Industry Expert Review Panel Recommendations on EOP-001, -002, and -003

September 23, 2013

IERP Recommendations		
Standard	**Requirement**	**Reason**
1. EOP-001-2.1b	R6.	P81. Duplicative of Requirement R4 and the Attachment.
2. EOP-002-3.1	R2.	P81. Duplicative. The requirement to take action is in Requirement R1.
3. EOP-002-3.1	R3.	P81. Duplicative of what is required to be in the plan under Attachment 1 of EOP-001-2.1b.
4. EOP-002-3.1	R6.	P81. Duplicative of BAL standards to meet CPS and DPS.
5. EOP-002-3.1	R9.	P81. This is a market (tariff) issue.
6. EOP-003-2	R2.	P81. Duplicative of PRC-010 and TPL standards.
7. EOP-003-2	R4.	P81. Duplicative of PRC-010 and TPL standards.
8. EOP-003-2	R5.	P81. Duplicative of Requirement R1 and also covered under standards for TOP (TOP-002-3).
9. EOP-003-2	R6.	P81. Duplicative. An entity does the same actions as when not islanded.
10. EOP-003-2	R7.	P81. Duplicative of PRC-010 Requirement R1.

EOP FYRT Consideration of Independent Expert Review Panel Recommendations

As part of their EOP Five-Year Review, the EOP FYRT has evaluated the Industry Expert Review Panel's findings related to the EOP standards and generally agrees with their recommendations, with exceptions and further considerations for the standard drafting team as noted below:

- ***EOP-001-2.1b*** – the EOP FYRT concurs with the recommendation to retire R6 in accordance with the applicable Paragraph 81 criteria (Requirements 6.1 and 6.3 under Criterion B7; Requirement R6.2 under Criterion B6; and Requirement R6.4 under Criterion A). In addition, the EOP FYRT also recommends that the future EOP SDT take into consideration retiring Requirements R3.1 under Criterion B7, Requirement R3.2 under Criterion B7 and Criterion A, and Requirement R3.4 under Criterion B1 of Paragraph 81. The EOP FYRT further recommends revising and merging EOP-001-2.b and EOP-002-3.1 into a single standard; revising Requirements R1, R2 and R5 and a review of Attachment 1.
- ***EOP-002-3.1*** – in addition to Requirements R6 and R9, the EOP FYRT recommends retiring Requirements R1 under Criterion B7 of Paragraph 81. The EOP FYRT further recommends that the future EOP SDT consider revising and merging EOP-001-2.b and EOP-002-3.1 into a single standard, which will include revising Requirement R3 and Attachment 1.
- ***EOP-003-2*** - the EOP FYRT recommends Requirements R2, R4 and R7 be moved to PRC-010-0 and revised in accordance with the other requirements in that standard. In addition to merging EOP-001-2.1b with EOP-002-3.1, the EOP FYRT recommends the future EOP SDT consider merging EOP-003-2, EOP-001-1-2.1b and EOP-002-3.1 into a single standard.

The EOP FYRT strongly recommends that the future EOP SDT consider merging and revising EOP-001-2.b and EOP-002-3.1 into a single standard. This will not only streamline and clarify the requirements after applying the Paragraph 81 criteria, but also will invoke the continuous improvement cycle of the reliability standards towards RBS which supports the RAI initiative with the objective of moving to a more sustainable Compliance and Enforcement Program.

\- - -

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Emergency Operations (EOP-001-3, EOP-002-4, EOP-003-3)		
Date Submitted:	October 17, 2013		
SAR Requester Information			
Name:	David McRee, Chair EOP Five-Year Review Team (FYRT)		
Organization:	Duke Energy		
Telephone:	(704) 382-9841	E-mail:	David.McRee@duke-energy.com
SAR Type (Check as many as applicable)			
☐ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
This SAR will address the Five-Year Review requirement for these standards.
Purpose or Goal (How does this request propose to address the problem described above?):
To improve the quality, relevance, and clarity of the standards. Also bring the standards into the Results Based Standards format.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
To increase the effectiveness of the three standards in their ability to ensure reliability of the BES.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The EOP SDT will consider the comments received from the EOP Five Year Review Team (FYRT), which includes consideration of industry comments and the report from the Industry Expert Review Panel. Recommendations for consideration are: • Modify the requirements and attachments to improve their clarity and measurability, while removing ambiguity • Move and/or streamline requirements • Eliminate requirements based on P81 criteria • Coordinate with Project 2008-02 UVLS to eliminate duplicative requirements • Apply Paragraph 81 criteria and recommendations from Independent Expert Review Panel on standards EOP-001, -002, and -003. To ensure a seamless transition from the EOP FYRT to the future EOP SDT, the EOP FYRT recommends the inclusion of interested EOP FYRT members to participate on the EOP SDT. In addition, the EOP FYRT should provide a high-level overview of their recommendations as a formal kick-off to the future EOP SDT meetings.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
See the attached Five-Year Review templates of the three standards, consideration of comments, issues and directives list, redlined standards (reflecting deletions), and the Industry Experts' anyalsis.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☒ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

Reliability Functions		
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards

Related Standards	
Standard No.	Explanation
BAL-001-0.1a	Real Power Balancing Control Performance
BAL-002-01	Disturbance control standard
BAL-002-WECC	Regional Contingency Reserve standard
COM-001-1.1	Telecommunications
COM-002-2	Communications and Coordination
PRC-010-0	Planning for Undervoltage Load shedding
PER-005-1	Training

Related SARs	
SAR ID	Explanation
	None

Regional Variances	
Region	Explanation
ERCOT	

Regional Variances	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Five-Year Review Template – EOP-001-2.1b

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-001-2.1b Emergency Operations Planning
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111, ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information *(to be completed by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:
   Requirement R3:

   - Requirement R3.1 should be covered by EOP-001-2.1b Requirement R4 in Attachment 1 (notifications that should be included in the plan are identified). COM-001 and COM-002 are descriptive in the identification of protocols to use and, thus, adequately cover the generic reference. With the recommended revision to Attachment 1 of EOP-001-2.1b, along with COM-001 and COM-002 generic reference, Requirement R3.1 would meet Criterion B7 as redundant, as well as Criterion A (Requirement R3.1 does little, if anything, to benefit or protect the reliable operation of the BES) of Paragraph 81 and should be retired.
   - Requirement R3.2 should be covered by EOP-001-2.1b Requirement R4 in Attachment 1, which lists the actions to take during capacity situations specified in the plan. Load reduction within timelines is covered in BAL-002 Requirement R2. With the recommended revision of EOP-001 Requirement R4, Requirement R3.2 would meet Criterion B7 as redundant, as well as Criterion A (R3.1 does little, if anything, to benefit or protect the reliable operation of the BES) of Paragraph 81 and should be retired.
   - Requirement R3.4 meets Paragraph 81 Criterion B1; staffing levels are administrative in nature and would result in an increase in efficiency in the ERO compliance program (it is a simple check off during an audit). Requirement R3.4 also meets with Criterion A of Paragraph 81, as a check-off does not enhance the reliability of the BES. Requirement R3.4 should be retired as falling under Criterion B1 and Criterion A of Paragraph 81.

   Requirement 6 in its entirety:

   - Requirement R6.1 is redundant with COM-001, meeting Criterion B7 as redundant under Paragraph 81 and should be retired.
   - Requirement R6.2 speaks to an action to be taken during capacity issues that is not feasible in accomplishing. Transaction arrangements are also a commercial practice and, thus, Requirement R6.2 meets Criterion B6 of Paragraph 81 and should be retired.

- Requirement R6.3 is redundant with EOP-001-2b Requirement R4 and Attachment 1, whereby meeting Criterion B7 as redundant under Paragraph 81 and should be retired.
- Requirement R6.4 does not provide for benefit for reliability of the BES, meeting Criterion A of Paragraph 81 and should be retired.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

    a. Is this a Version 0 Reliability Standard?
    b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
    c. Are the requirements consistent with the purpose of the Reliability Standard?

    ☒ Yes

    ☐ No

    Please summarize your assessment:
    The 2009-03 Emergency Operations Five-Year Review Team (EOP FYRT) recommends that EOP-001-2.b and EOP-002-3.1 be revised and merged into a single standard identifying clearly and separately the Transmission Operator, Generation Operator and Reliability Coordinator issues as they relate to the BA and TOP (to address Paragraph 548 of Order 693) and how it needs to be planned and implemented for on the BES by the specific functional entities.

    - Requirement R1 needs clarity provided as to what an operating agreement constitutes, and adjust the VSL to reflect current interpretations with the number of agreements needed. Requirement R1 must also account for current interpretations found in the Appendix and other interpretations.
    - Requirement R2 needs clarity provided, as instructed by the Commission, on the ambiguity of the EOP standards as they relate to the responsibilities of the Transmission Operator and Balancing Authority.
    - Requirement R5, the need to share emergency plans with neighboring Transmission Operators and Balancing Authorities, should be removed as an administrative burden (identified in P81); however, the remaining language of the requirement should be affirmed.
    - Review is recommended for Attachment 1 as it relates to the GOP in light of recent BES events (Cold Weather Event).

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☒ Yes

☐ No

Please explain:
Appendix 1 attempts to define what a remote Balancing Authority is and should be addressed in future revisions of the Standard

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

   Additional measures must be provided with this standard. There are no performance measures. There are no VRFs with this standard. Requirement R1, once recommended clarity is provided as to what an operating agreement constitutes, adjustment to the VSL will be necessary to reflect current interpretations with the number of agreements needed.

   ☐ Yes

   ☒ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

   ☐ Yes

   ☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☐ Yes

☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE – Requirement R1, R2, R5 and Attachment 1

☒ RETIRE – Requirements R3.1, R3.2, R3.4, R6.1, R6.2, R6.3, R6.4

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE – Requirements R1, R2, R5 and Attachment 1

☒ RETIRE – Requirements R3.1, R3.2, R3.4; Requirement R6 in its entirety; R6.1, R6.2, R6.3, R6.4

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

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[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Five-Year Review Template – EOP-002-3

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-002-3.1 Capacity and Energy Emergencies
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111,ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   - Requirement R1 is redundant with IRO-001 and PER-001-2 and should be retired under Criterion B7 of Paragraph 81.
   - Requirement R6 is redundant with BAL-002-1a and should be retired under Criterion B7 of Paragraph 81.
   - Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR, and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired. Due to the retirement of R9, LSE applicability should be removed in the standard.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

Please summarize your assessment:
The EOP FYRT recommends that EOP-001-2b and EOP-002-3.1 be revised and merged into a single standard to address redundancy in the stating that a plan should be implemented. Both standards are different enough that those requirements not identified in retirement recommendations under Paragraph 81 should be retained.

Requirement R8 and Attachment 1 have several issues regarding applicability to different functions and should be revised to eliminate discrepancies and for clarity. Attachment 1 needs to be reviewed for consistency with IRO and TOP standards. The EOP FYRT recommends review of the uniqueness as it relates to ERCOT and similarly situated BAs. The EOP FYRT recommends the future EOP SDT address the directive in Paragraph 573 of Order 693.

The EOP FYRT further recommends a language change in Requirement R2, replacing "interconnected system" with "Bulk Electric System." Requirements R3 and R4 need to be reviewed by the future EOP SDT to further define the word "emergency" (as Capacity Emergency, Emergency, and Energy Emergency are already NERC defined terms). The EOP FYRT recommends the following sentence in Requirement R5 to be struck: "Such unilateral adjustment may overload transmission facilities."

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes

☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

☒ Yes

☐ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or

consistency with other Reliability Standards? If you answered “Yes,” please describe the changes needed to achieve formatting and language consistency:

☐ Yes

☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered “Yes,” please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised: Requirement R9 (recommended for retirement under Paragraph 81) the TSP now has the ability to change the Transmission priority, which is in turn reflected in the IDC.

   ☒ Yes

   ☐ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE (and merge with EOP-001-2b)

☒ RETIRE – Requirements R1, R6 and R9 in its entirety.

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE (and merge with EOP-001-2b); Requirement R2, replacing “interconnected system” with “Bulk Electric System;” language revision in Requirement R2; Requirements R3 and R4 need to be reviewed by the future EOP SDT to further define the word “emergency” (as Capacity Emergency, Emergency, and Energy Emergency are already NERC defined terms); Requirement R5, strike “Such unilateral adjustment may overload transmission facilities.”

☒ RETIRE – Requirements R1, R6, and R9 in its entirety. Due to the retirement of R9, LSE applicability should be removed in the standard.

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Five-Year Review Template – EOP-003-2

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-003-2 Load Shedding Plans
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111, ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   - Requirements R5 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R5 speaks to shedding loads in steps; that same process will be done in Requirement R1. Requirement R5 should be retired under Criterion B7 of Paragraph 81.
   - Requirements R6 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R6 speaks of two events that must be valid to tell the BA or TOP to shed more load, but overall the action of shedding load to meet insufficient generation is the same as stated in Requirement R1. Requirement R6 should be retired under Criterion B7 of Paragraph 81.
   - EOP-003-2– Recommend that Requirements R2, R4 and R7 be moved to PRC-010-0 or otherwise addressed during Project 2008-02 – Undervoltage Load Shedding.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

Please summarize your assessment:
The EOP FYRT team believes that Requirements R2, R4 and R7 should be coordinated with the revision of PRC-010 (Project 2008-02 Undervoltage Load Shedding) for inclusion in that standard. This is consistent with the review that was done for automatic underfrequency requirements and should also be performed for automatic undervoltage requirements.

Based on the recommendations received during the comment period, EOP FYRT further recommends R1 and R8 be considered to be combined. The EOP FYRT also received comments that EOP-003-2 should be combined with EOP-001-2.1b and EOP-002-3.1, and the EOP FYRT recommends this be evaluated in the SAR. In addition, the EOP FYRT recommends that the future EOP SDT evaluate the separation of the functional entity capabilities of the BA and the TOP responsibilities.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes
☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

The Measures and Data retention should be reviewed and updated

☐ Yes
☒ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

☐ Yes
☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☐ Yes

   ☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE – Retire Requirements R5, R6, R2, R4 and R7 and address directives in Paragraphs 595 and 603 of Order 693

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*: See responses to questions 1, 2, and 4 above.

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE - Retire Requirements R5, R6, R2, R4 and R7 and address directives in Paragraphs 595 and 603 or Order 693; recommend for consideration Requirements R1 and R8 be combined; consider combining EOP-003-2 with EOP-001-2.1b and EOP-002-3.1; evaluate the separation of the functional entity capabilities of the BA and TOP responsibilities.

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

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[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Unofficial Comment Form

Project 2009-03 Emergency Operations

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard Authorization Request (SAR). The electronic comment form must be completed by **December 5, 2013.**

If you have questions please contact Laura Anderson or by telephone at 404-446-9671.

All documents for this project are available on the project page.

Background Information
This posting is soliciting informal comment.

On April 22, 2013, the NERC Standards Committee appointed eight subject matter experts to serve on the EOP Five Year Review Team (FYRT). As part of its review, the EOP FYRT referenced background documents including 1) the previously-posted Project 2009-03 EOP SAR (posted 12/07/09 – 01/15/2010, and last modified on 11/05/2010); 2) the currently-enforceable EOP standards; 3) outstanding issues and directives pertaining to the EOP standards; 4) the Independent Experts Report; and, 4) Paragraph 81 criteria. Based on this review, the EOP FYRT developed a set of recommendations for EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

The EOP FYRT recommendations for EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 were posted for a 45-day comment period from August 6, 2013 through September 19, 2013. There were 25 sets of responses, including comments from approximately 94 different people from approximately 58 companies, representing 8 of the 10 Industry Segments.

The EOP FYRT carefully considered the stakeholder comments received during the posting period and, based on comments, made revisions to its recommendations. To further support its recommendations, the EOP FYRT developed redlined versions of the standards and developed a supplemental SAR for Project 2009-03. Many improvements suggested by stakeholders during the comment period were incorporated into the final recommendations and redlined standards being provided to the Standards Committee.

Based on the EOP FYRT’s discussions and recommendations received during the comment period, the EOP FYRT recommends that the EOP SDT consider the following:

- EOP-001-2.1b, Requirements R1 and R8 should be considered for combination
- The EOP FYRT recommended merging EOP-001-2.1b and EOP-002-3.1 into a single standard and stakeholders agreed with this recommendation. Some stakeholders commented that EOP-003-2

should be included in the merger of EOP-001-2.1b and EOP-002-3.1; although the EOP FYRT did not fully support these comments, a recommendation was made in the Five-Year Review Templates for the future EOP SDT to consider merging these three standards into a single standard.

The complete recommendations of the EOP FYRT are in the attached Five-year Review Templates and redlined versions of the standards are provided as a starting point for the Project-2009-03-Emergency Operations drafting team.

This project addresses directives in Paragraph 573 of FERC Order No. 693[1] and Paragraph 595 of FERC Order No. 693[2] and provides additional clarity to many requirements, as well as retiring requirements that meet the criteria of Paragraph 81. Project 2009-03 addresses Emergency Operations and requires coordination with Project 2008-02 Undervoltage Load Shedding to ensure that duplicative requirements are not retained as PRC-010 is developed; therefore, the EOP FYRT considers this project to be high priority.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. The scope of this project includes:

- Address Five-Year requirement for EOP-001-2.1b, EOP-002-3.1 and EOP-003-2
- Improve quality, relevance and clarity of the standards
- Bring standards into Results-Based format
- Apply Paragraph 81 criteria and recommendations from Independent Expert Review Panel on standards EOP-001, -002, and -003
- Coordinate with Project 2008-02 UVLS to eliminate duplicative requirements

Do you agree with this scope? If not, please explain.

☐ Yes

☐ No

Comments:

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1 Order No. 693 at P 573 “Demand response covers considerably more resources than interruptible load. Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements.”

2 Order No. 693 at P 595: “The Commission directs the ERO to address the minimum load and maximum time concerns of the Commission through the Reliability Standards development process.”

2. The SAR identifies a list of reliability functions that may be assigned responsibility for requirements in the set of standards addressed by this SAR. Do you agree with the list of proposed applicable functional entities? If no, please explain.
   ☐ Yes
   ☐ No
   Comments:

3. Are you aware of any regional variances that will be needed as a result of this project? If yes, please identify the regional variance:
   ☐ Yes
   ☐ No
   Comments:

4. Are you aware of any business practice that will be needed or that will need to be modified as a result of this project? If yes, please identify the business practice:
   ☐ Yes
   ☐ No
   Comments:

5. Are you aware of any Canadian provincial or other regulatory requirements that may need to be considered during this project in order to develop a continent-wide approach to the standard(s)? If yes, please identify the jurisdiction and specific regulatory requirements.
   ☐ Yes
   ☐ No
   Comments:

6. If you have any other comments on this SAR that you haven't already mentioned above, please provide them here:
   Comments:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Five Year Review Team Recommendations posted for informal comment period (August 6-September 19, 2013).
2. Developed SAR, proposed revisions to the standard and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).

Description of Current Draft

This is the first draft of the proposed standard presented to the NERC Standards Committee for authorization to ~~moving~~ move the SAR forward to standard development. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	
45-day Formal Comment Period with Parallel Initial Ballot	
30-day Formal Comment Period with Parallel Successive Ballot	
Recirculation ballot	
BOT adoption	

Effective Dates

First day of the second calendar quarter beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking
0	**February 8, 2005**	**Adopted by the Board of Trustees**	**New**
0	**April 1, 2005**	**Effective Date**	**New**
0	**August 8, 2005**	**Removed "Proposed" from Effective Date**	**Errata**
1	**October 17, 2008**	**Deleted R2** **Replaced Levels of Non-compliance with the February 28, 2008 BOT approved Violation Severity Levels** **Corrected typographical errors in BOT approved version of VSLs**	**Revised** **IROL Project**
2	**August 5, 2009**	**Removed R2.4 as redundant with EOP-005-2 Requirement R1 for the Transmission Operator; the Balancing Authority does not need a restoration plan.**	**Revised** **Project 2006-03**
2	**August 5, 2009**	**Adopted by NERC Board of Trustees: August 5, 2009**	**Revised**
2	**March 17, 2011**	**FERC Order issued approving EOP-001-2 (Clarification issued on July 13, 2011)**	**Revised**
2b	**November 4, 2010**	**Adopted by NERC Board of Trustees**	**Project 2008-09 - Interpretation of Requirement R1**
2b	**November 4, 2010**	**Adopted by NERC Board of Trustees**	**Project 2009-28 - Interpretation of Requirement R2.2**
2b	**December 15, 2011**	**FERC Order issued approving Interpretation of R1 and R2.2 (Order effective December 15, 2011)**	**Project 2008-09 - Interpretation of Requirement R1 and**

			Project 2009-28 - Interpretation of Requirement R2.2
2.1b	**March 8, 2012**	**Errata adopted by Standards Committee; (changed title and references to Attachment 1 to omit inclusion of version numbers and corrected references in Appendix 1 Question 4 from “EOP-001-0” to “EOP-001-2”)**	**Errata**
2.1b	**September 13, 2012**	**FERC approved**	**Errata**
3	**TBD**	**TBD**	**Five Year Review team**

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Emergency Operations Planning**

2. **Number:** EOP-001-3~~2.1b~~

3. **Purpose:** Each Transmission Operator and Balancing Authority needs to develop, maintain, and implement a set of plans to mitigate operating emergencies. These plans need to be coordinated with other Transmission Operators and Balancing Authorities, and the Reliability Coordinator.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authorities

   4.1.2 Transmission Operators

5. **Background:**

   Text

B. Requirements and Measures

R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities. *[Violation Risk Factor: High] [Time Horizon: TBD]*

Rationale for R1:

M1. The Transmission Operator and Balancing Authority shall have its emergency plans available for review by the Regional Reliability Organization at all times.

R2. Each Transmission Operator and Balancing Authority shall: *[Violation Risk Factor: Medium] [Time Horizon: TBD]*

Rationale for R2:

2.1. Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity.

2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.

2.3. Develop, maintain, and implement a set of plans for load shedding.

M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self-assessments available for review by the Regional Reliability Organization at all times.

R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include: *[Violation Risk Factor: Medium] [Time Horizon: TBD]*

Rationale for R3:

3.1. ~~Communications protocols to be used during emergencies~~.

3.2. ~~A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions~~.

3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities.

3.4. ~~Staffing levels for the emergency~~.

M3. Text

R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan. *[Violation Risk Factor: Medium] [Time Horizon: TBD]*

Rationale for R4:

M4. Text

R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities. *[Violation Risk Factor: Medium] [Time Horizon: TBD]*

Rationale for R5:

M5. Text

~~**R6.** The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable: *[Violation Risk Factor: Medium] [Time Horizon: TBD]*~~

Rationale for R6:

~~**6.1.** The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.~~

~~**6.2.** The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used.~~

~~**6.3.** The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.)~~

~~**6.4.** The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.~~

M6. Text

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, R4, and R5 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R3 for the most recent three calendar months plus the current month.
- If a Balancing Authority or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1		High	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for less than 25% of the adjacent BAs. Or less than 25% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 25% to 50% of the adjacent BAs. Or 25 to 50% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 50% to 75% of the adjacent BAs. Or 50% to 75% of those agreements do not contain provisions for emergency assistance.	The Balancing Authority failed to demonstrate the existence of the necessary operating agreements for 75% or more of the adjacent BAs. Or more than 75% of those agreements do not contain provisions for emergency assistance.
R2		Medium	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	N/A	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.
R2.1			The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity are missing minor details or minor program/procedural	The Transmission Operator or Balancing Authority's has demonstrated the existence of emergency plans to mitigate insufficient generating capacity	The Transmission Operator or Balancing Authority's emergency plans to mitigate insufficient generating capacity emergency plans are neither maintained nor	The Transmission Operator or Balancing Authority has failed to develop emergency mitigation plans for insufficient generating capacity.

			elements.	emergency plans but the plans are not maintained.	implemented.	
R2.2			The Transmission Operator or Balancing Authority’s plans to mitigate transmission system emergencies are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of transmission system emergency plans but are not maintained.	The Transmission Operator or Balancing Authority's transmission system emergency plans are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement operating emergency mitigation plans for emergencies on the transmission system.
R2.3			The Transmission Operator or Balancing Authority’s load shedding plans are missing minor details or minor program/procedural elements.	The Transmission Operator or Balancing Authority's has demonstrated the existence of load shedding plans but are not maintained.	The Transmission Operator or Balancing Authority's load shedding plans are partially compliant with the requirement but are neither maintained nor implemented.	The Transmission Operator or Balancing Authority has failed to develop, maintain, and implement load shedding plans.
R3		Medium	The Transmission Operator or Balancing Authority failed to comply with one (1) of the sub-components.	The Transmission Operator or Balancing Authority failed to comply with two (2) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with three (3) of the sub-components.	The Transmission Operator or Balancing Authority has failed to comply with all four (4) of the sub-components.

~~R3.1~~			~~The Transmission Operator or Balancing Authority's communication protocols included in the emergency plan are missing minor program/procedural elements.~~	~~N/A~~	~~N/A~~	~~The Transmission Operator or Balancing Authority has failed to include communication protocols in its emergency plans to mitigate operating emergencies.~~
~~R3.2~~			~~The Transmission Operator or Balancing Authority's list of controlling actions has resulted in meeting the intent of the requirement but is missing minor program/procedural elements.~~	~~N/A~~	~~The Transmission Operator or Balancing Authority provided a list of controlling actions, however the actions fail to resolve the emergency within NERC-established timelines.~~	~~The Transmission Operator or Balancing Authority has failed to provide a list of controlling actions to resolve the emergency.~~
R3.3			The Transmission Operator or Balancing Authority has demonstrated coordination with Transmission Operators and Balancing Authorities but is missing minor program/procedural elements.	N/A	N/A	The Transmission Operator or Balancing Authority has failed to demonstrate the tasks to be coordinated with adjacent Transmission Operator and Balancing Authorities as directed by the requirement.

~~R3.4~~			~~The Transmission Operator or Balancing Authority's emergency plan does not include staffing levels for the emergency~~	~~N/A~~	~~N/A~~	~~N/A~~
R4		Medium	The Transmission Operator and Balancing Authority's emergency plan has complied with 90% or more of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with 70% to 90% of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with between 50% to 70% of the number of sub-components.	The Transmission Operator and Balancing Authority's emergency plan has complied with 50% or less of the number of sub-components
R5		Medium	The Transmission Operator and Balancing Authority is missing minor program/procedural elements.	The Transmission Operator and Balancing Authority has failed to annually review one of it's emergency plans	The Transmission Operator and Balancing Authority has failed to annually review two of its emergency plans or communicate with one of it's neighboring Balancing Authorities.	The Transmission Operator and Balancing Authority has failed to annually review and/or communicate any emergency plans with its Reliability Coordinator, neighboring Transmission Operators or Balancing Authorities.
~~R6~~		~~Medium~~	~~The Transmission Operator and/or the Balancing Authority failed to comply with one (1) of the sub-components.~~	~~The Transmission Operator and/or the Balancing Authority failed to comply with two (2) of the sub-components.~~	~~The Transmission Operator and/or the Balancing Authority has failed to comply with three (3) of the sub-components.~~	~~The Transmission Operator and/or the Balancing Authority has failed to comply with four (4) or more of the sub-~~

						~~components.~~
~~R6.1~~			~~The Transmission Operator or Balancing Authority has failed to establish and maintain reliable communication between interconnected systems.~~	~~N/A~~	~~N/A~~	~~N/A~~
~~R6.2~~			~~The Transmission Operator or Balancing Authority has failed to arrange new interchange agreements to provide for emergency capacity or energy transfers with required entities when existing agreements could not be used.~~	~~N/A~~	~~N/A~~	~~N/A~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Attachment 1-EOP-001

Elements for Consideration in Development of Emergency Plans

1. Fuel supply and inventory — An adequate fuel supply and inventory plan that recognizes reasonable delays or problems in the delivery or production of fuel.
2. Fuel switching — Fuel switching plans for units for which fuel supply shortages may occur, e.g., gas and light oil.
3. Environmental constraints — Plans to seek removal of environmental constraints for generating units and plants.
4. System energy use — The reduction of the system's own energy use to a minimum.
5. Public appeals — Appeals to the public through all media for voluntary load reductions and energy conservation including educational messages on how to accomplish such load reduction and conservation.
6. Load management — Implementation of load management and voltage reductions, if appropriate.
7. Optimize fuel supply — The operation of all generating sources to optimize the availability.
8. Appeals to customers to use alternate fuels — In a fuel emergency, appeals to large industrial and commercial customers to reduce non-essential energy use and maximize the use of customer-owned generation that rely on fuels other than the one in short supply.
9. Interruptible and curtailable loads — Use of interruptible and curtailable customer load to reduce capacity requirements or to conserve the fuel in short supply.
10. Maximizing generator output and availability — The operation of all generating sources to maximize output and availability. This should include plans to winterize units and plants during extreme cold weather.
11. Notifying IPPs — Notification of cogeneration and independent power producers to maximize output and availability.
12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.
13. Load curtailment — A mandatory load curtailment plan to use as a last resort. This plan should address the needs of critical loads essential to the health, safety, and welfare of the community. Address firm load curtailment.

14. Notification of government agencies — Notification of appropriate government agencies as the various steps of the emergency plan are implemented.

15. Notifications to operating entities — Notifications to other operating entities as steps in emergency plan are implemented.

Appendix 1

Requirement Number and Text of Requirement
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.
Questions:
1. What is the definition of emergency assistance in the context of this standard? What scope and time horizons, if any, are considered necessary in this definition? 2. What was intended by using the adjective "adjacent" in Requirement 1? Does "adjacent Balancing Authorities" mean "All" or something else? Is there qualifying criteria to determine if a very small adjacent Balancing Authority area has enough capacity to offer emergency assistance? 3. What is the definition of the word "remote" as stated in the last phrase of Requirement 1? Does remote mean every Balancing Authority who's area does not physically touch the Balancing Authority attempting to comply with this Requirement? 4. Would a Balancing Authority that participates in a Reserve Sharing Group Agreement, which meets the requirements of Reliability Standard BAL-002-0, Requirement 2, have to establish additional operating agreements to achieve compliance with Reliability Standard EOP-001-2, Requirement 1?
Responses:
1. In the context of this standard, emergency assistance is emergency energy. Emergency energy would normally be arranged for during the current operating day. The agreement should describe

the conditions under which the emergency energy will be delivered to the responsible Balancing Authority. 2. The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections. 3. A remote Balancing Authority is a Balancing Authority other than an Adjacent Balancing Authority. A Balancing Authority is not required to have arrangements in place to obtain emergency energy assistance with any remote Balancing Authorities. A Balancing Authority's agreement(s) with Adjacent Balancing Authorities does (do) not preclude the Adjacent Balancing Authority from purchasing emergency energy from remote Balancing Authorities. 4. A Reserve Sharing Group agreement that contains provisions for emergency assistance may be used to meet Requirement R1 of EOP-001-2.

Appendix 2

Requirement Number and Text of Requirement
R2.2. Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.
Questions:
Does the BA need to develop a plan to maintain a load-interchange-generation balance during operating emergencies and follow the directives of the TOP?
Questions:

The answer to both parts of the question is yes. The Balancing Authority is required by the standard to develop, maintain, and implement a plan. The plan must consider the relationships and coordination with the Transmission Operator for actions directly taken by the Balancing Authority. The Balancing Authority must take actions either as directed by the Transmission Operator or the Reliability Coordinator (reference TOP-001-1, Requirement R3), or as previously agreed to with the Transmission Operator or the Reliability Coordinator to mitigate transmission emergencies. As stated in Requirement R4, the emergency plan shall include the applicable elements in "Attachment 1 –EOP-001."

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Five Year Review Tam Recommendations posted for informal comment period (August 6-September 19, 2013).
2. Developed SAR, proposed revisions to the standard and response to comments posted (December 1, 2008).
3. SC authorized moving the SAR forward to standard development (December 16–17, 2008).

Description of Current Draft

This is the first draft of the proposed standard presented to the NERC Standards Committee for authorization ~~moving~~ to move the SAR forward to standard development. This draft includes the modifications based on comments submitted by stakeholders, as well as items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
30-day Formal Comment Period	
45-day Formal Comment Period with Parallel Initial Ballot	
30-day Formal Comment Period with Parallel Successive Ballot	
Recirculation ballot	
BOT adoption	

Effective Dates

First day of the second calendar quarter beyond the date this standard is approved by applicable regulatory authorities, or in those jurisdictions where regulatory approval is not required, the standard becomes effective on the first day of the second calendar quarter beyond the date this standard is approved by the NERC Board of Trustees, or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities.

Version History

Version	Date	Action	Change Tracking
0	**April 1, 2005**	**Effective Date**	**New**
0	**August 8, 2005**	**Removed "Proposed" from Effective Date**	**Errata**
1	**September 19, 2006**	**Changes R7. to refer to "Requirement 6" instead of "Requirement 7"**	**Errata**
2	**November 1, 2006**	**Adopted by Board of Trustees**	**Revised**
2	**November 1, 2006**	**Corrected numbering in Section A.4. "Applicability."**	**Errata**
2	**October 1, 2007**	**Added to Section 1 inadvertently omitted "4.3. Load-Serving Entities**	**Errata**
2.1	**October 29, 2008**	**BOT adopted errata changes; updated version number to "2.1"**	**Errata**
2.1	**May 13, 2009**	**FERC Approved**	**Revised**
3	**June 4, 2010**	**Modified to address Order No. 693 Directives contained in paragraphs 582.**	**Revised.**
3	**August 5, 2010**	Adopted by NERC Board of Trustees	**New**
3.1	**March 8, 2012**	Errata adopted by Standards Committee; (Updated title of Attachment 1 and changed references to Attachment 1 throughout Standard from "Attachment 1-EOP-002-0 Energy Emergency Alert Levels" to "Attachment 1-EOP-002 Energy Emergency Alerts". Removed parenthetical in Requirement R9 referencing a retired Attachment in IRO-006)	**Errata**
3.1	**September 13, 2012**	FERC Approved	**Errata**
4	**TBD**	TBD	**Five Year Review**

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Capacity and Energy Emergencies**
2. **Number:** EOP-002-~~4~~3.~~1~~
3. **Purpose:** To ensure Reliability Coordinators and Balancing Authorities are prepared for capacity and energy emergencies.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authorities

   4.1.2 Reliability Coordinators

   ~~**4.1.3** Load-Serving Entities~~
5. **Background:**

   Text

B. Requirements and Measures

~~**R1.** Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies. *[Violation Risk Factor: High] [Time Horizon: TBD]*~~

Rationale for R1:

~~**M1.** Text~~

~~**R2.**~~**R1.** Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan to reduce risks to the ~~interconnected~~ Bulk Electric ~~system~~System. *[Violation Risk Factor: High] [Time Horizon: TBD]*

Rationale for R2:

~~**M2.**~~**M1.** Text

~~R3.~~R2. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities. *[Violation Risk Factor: High] [Time Horizon: TBD]*

Rationale for R3:

~~M3.~~M2. Text

~~R4.~~R3. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load. *[Violation Risk Factor: High] [Time Horizon: TBD*

Rationale for R4:

~~M4.~~M3. Text

~~R5.~~R4. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. ~~Such unilateral adjustment may overload transmission facilities.~~ *[Violation Risk Factor: High] [Time Horizon: TBD]*

Rationale for R5:

~~M5.~~M4. Text

~~**R6.** If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so.~~

~~These remedies include, but are not limited to: *[Violation Risk Factor: High] [Time Horizon: TBD]*~~

~~**6.1.** Loading all available generating capacity.~~

~~**6.2.** Deploying all available operating reserve.~~

~~**6.3.** Interrupting interruptible load and exports.~~

~~**6.4.** Requesting emergency assistance from other Balancing Authorities.~~

~~**6.5.** Declaring an Energy Emergency through its Reliability Coordinator; and~~

~~**6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.~~

Rationale for R6:

~~**M6.** Text~~

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~~R7.~~R5. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards,~~Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition~~, the Balancing Authority shall: *[Violation Risk Factor: High] [Time Horizon: TBD]*

Rationale for R7:

~~7.1.~~5.1. R7.1. Manually shed firm load without delay to return its ACE to zero; and

~~7.2.~~5.2. R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."

~~M7.~~M5. Text

~~R8.~~R6. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required. *[Violation Risk Factor: High] [Time Horizon: TBD]*

Rationale for R9:

~~M8.~~M6. Text

~~**R9.** When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff: *[Violation Risk Factor: High] [Time Horizon: TBD]*~~

Rationale for R9:

~~**9.1.** The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."~~

~~**9.2.** The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.~~

~~**9.3.** The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.~~

~~**9.4.** The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.~~

~~M9.~~M7. Text

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority and Transmission Service Provider shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall maintain evidence to show compliance with R1, R2, R4, and R5 for the most recent three calendar months plus the current month.
- The Transmission Service Provider shall maintain evidence to show compliance with R3 for the most recent three calendar months plus the current month.

- If a Balancing Authority or Transmission Service Provider is found non-compliant, it shall keep information related to the non-compliance until found compliant.

1.3. The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records. **Compliance Monitoring and Assessment Processes:**

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
~~**R1**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority or Reliability Coordinator does not have responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area OR The Balancing Authority or Reliability Coordinator did not exercise its authority to alleviate capacity and energy emergencies.~~
R2		**High**	N/A	N/A	N/A	The Balancing Authority did not implement its capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system.
R3		**High**	N/A	N/A	The Balancing Authority communicated its current and future system conditions to its Reliability Coordinator but did not communicate to one or more of its neighboring Balancing Authorities.	The Balancing Authority has failed to communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.
R4		**High**	N/A	N/A	N/A	The Balancing Authority has failed to perform the necessary actions as required and stated in the

						requirement.
R5		**High**	N/A	N/A	The Balancing Authority used the assistance provided by the Interconnection's frequency bias for more time than needed to implement corrective actions.	The Balancing Authority used the assistance provided by the Interconnection's frequency bias for more time than needed to implement corrective actions and unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes.
~~**R6**~~		~~**High**~~	~~The Balancing Authority failed to comply with one of the sub-components.~~	~~The Balancing Authority failed to comply with 2 of the sub-components.~~	~~The Balancing Authority failed to comply with 3 of the sub-components.~~	~~The Balancing Authority failed to comply with more than 3 of the sub-components.~~
~~**6.1**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority did not use all available generating capacity.~~
~~**6.2**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority did not deploy all of its available operating reserve.~~
~~**6.3**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority did not interrupt interruptible load and exports.~~
~~**6.4**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority did not request emergency assistance from other Balancing Authorities.~~
~~**6.5**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority did not declare an Energy~~

						~~Emergency through its Reliability Coordinator.~~
~~6.6~~		**~~High~~**	~~N/A~~	~~N/A~~	~~N/A~~	~~The Balancing Authority did not implement one or more of the procedures stated in the requirement.~~
R7		**High**	N/A	N/A	The Balancing Authority has met only one of the two requirements	The Balancing Authority has not met either of the two requirements
7.1		**High**	N/A	N/A	N/A	The Balancing Authority did not manually shed firm load without delay to return it's ACE to zero.
7.2		**High**	The Balancing Authority's implementation of an Energy Emergency Alert has missed minor program/procedural elements in Attachment 1-EOP-002-0.	N/A	N/A	The Balancing Authority has failed to meet one or more of the requirements of Attachment 1-EOP-002-0.
R8		**High**	The Reliability Coordinator's implementation of an Energy Emergency Alert has missed minor program/procedural elements in Attachment 1-EOP-002-0.	N/A	N/A	The Reliability Coordinator has failed to meet one or more of the requirements of Attachment 1-EOP-002-0.
~~R9~~		**~~High~~**	~~The Reliability Coordinator failed to comply with one (1) of the sub-components.~~	~~The Reliability Coordinator failed to comply with two (2) of the sub-components.~~	~~The Reliability Coordinator has failed to comply with three (3) of the sub-components.~~	~~The Reliability Coordinator has failed to comply with all four (4) of the sub-components.~~
~~9.1~~		**~~High~~**	~~N/A~~	~~N/A~~	~~N/A~~	~~The Load-Serving Entity failed to request its Reliability Coordinator to initiate an Energy~~

						~~Emergency Alert.~~
~~**9.2**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator has failed to report to NERC as directed in the requirement.~~
~~**9.3**~~		~~**Lower**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator failed to use EEA 1 to forecast the change of the priority of transmission service as directed in the requirement.~~
~~**9.4**~~		~~**Lower**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Reliability Coordinator failed to use EEA 2 to announce the change of the priority of transmission service as directed in the requirement.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Attachment 1-EOP-002
Energy Emergency Alerts

Introduction
This Attachment provides the procedures by which a Load Serving Entity can obtain capacity and energy when it has exhausted all other options and can no longer provide its customers' expected energy requirements. NERC defines this situation as an "Energy Emergency." NERC assumes that a capacity deficiency will manifest itself as an energy emergency.

The Energy Emergency Alert Procedure is initiated by the Load Serving Entity's Reliability Coordinator, who declares various Energy Emergency Alert levels as defined in Section B, "Energy Emergency Alert Levels," to provide assistance to the Load Serving Entity.

The Load Serving Entity who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Requirements

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a Balancing Authority, or 3) upon the request of a Load Serving Entity.

1.1. **Situations for initiating alert.** An Energy Emergency Alert may be initiated for the following reasons:

- When the Load Serving Entity is, or expects to be, unable to provide its customers' energy requirements, and has been unsuccessful in locating other systems with available resources from which to purchase, or
- The Load Serving Entity cannot schedule the resources due to, for example, Available Transfer Capability (ATC) limitations or transmission loading relief limitations.

2. **Notification.** A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The Reliability Coordinator shall also notify the other Reliability Coordinators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction
To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established three levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining energy

emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **Alert 1 — All available resources in use.**

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity foresees or is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves, and

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **Alert 2 — Load management procedures in effect**.

Circumstances:

- Balancing Authority, Reserve Sharing Group, or Load Serving Entity is no longer able to provide its customers' expected energy requirements, and is designated an Energy Deficient Entity.
- Energy Deficient Entity foresees or has implemented procedures up to, but excluding, interruption of firm load commitments. When time permits, these procedures may include, but are not limited to:
    - o Public appeals to reduce demand.
    - o Voltage reduction.
    - o Interruption of non-firm end use loads in accordance with applicable contracts[1].
    - o Demand-side management.
    - o Utility load conservation measures.

During Alert 2, Reliability Coordinators, Balancing Authorities, and Energy Deficient Entities have the following responsibilities:

2.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity shall communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator shall post the declaration of the alert level along with the name of the Energy Deficient Entity and, if applicable, its Balancing Authority on the NERC website.

2.2 Declaration period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority, and Transmission Providers**.**

[1] For emergency, not economic, reasons.

Application Guidelines

2.3 Sharing information on resource availability. A Balancing Authority and market participants with available resources shall immediately contact the Energy Deficient Entity. This should include the possibility of selling non-firm (recallable) energy out of available Operating Reserves. The Energy Deficient Entity shall notify the Reliability Coordinators of the results.

2.4 Evaluating and mitigating transmission limitations. The Reliability Coordinators shall review all System Operating Limits (SOLs) and Interconnection Reliability Operating Limits (IROLs) and transmission loading relief procedures in effect that may limit the Energy Deficient Entity's scheduling capabilities. Where appropriate, the Reliability Coordinators shall inform the Transmission Providers under their purview of the pending Energy Emergency and request that they increase their ATC by actions such as restoring transmission elements that are out of service, reconfiguring their transmission system, adjusting phase angle regulator tap positions, implementing emergency operating procedures, and reviewing generation redispatch options.

2.4.1 Notification of ATC adjustments. Resulting increases in ATCs shall be simultaneously communicated to the Energy Deficient Entity and the market via posting on the appropriate OASIS websites by the Transmission Providers.

2.4.2 Availability of generation redispatch options. Available generation redispatch options shall be immediately communicated to the Energy Deficient Entity by its Reliability Coordinator.

2.4.3 Evaluating impact of current transmission loading relief events. The Reliability Coordinators shall evaluate the impact of any current transmission loading relief events on the ability to supply emergency assistance to the Energy Deficient Entity. This evaluation shall include analysis of system reliability and involve close communication among Reliability Coordinators and the Energy Deficient Entity.

2.4.4 Initiating inquiries on reevaluating SOLs and IROLs. The Reliability Coordinators shall consult with the Balancing Authorities and Transmission Providers in their Reliability Areas about the possibility of reevaluating and revising SOLs or IROLs.

2.5 Coordination of emergency responses. The Reliability Coordinator shall communicate and coordinate the implementation of emergency operating responses.

2.6 Energy Deficient Entity actions. Before declaring an Alert 3, the Energy Deficient Entity must make use of all available resources. This includes but is not limited to:

2.6.1 All available generation units are on line. All generation capable of being on line in the time frame of the emergency is on line including quick-start and peaking units, regardless of cost.

2.6.2 Purchases made regardless of cost. All firm and non-firm purchases have been made, regardless of cost.

2.6.3 Non-firm sales recalled and contractually interruptible loads and demand-side management curtailed. All non-firm sales have been recalled, contractually interruptible retail loads curtailed, and demand-side management activated within provisions of the agreements.

2.6.4 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.

3. Alert 3 — Firm load interruption imminent or in progress.

Circumstances:

- Balancing Authority or Load Serving Entity foresees or has implemented firm load obligation interruption. The available energy to the Energy Deficient Entity, as determined from Alert 2, is only accessible with actions taken to increase transmission transfer capabilities.

3.1 Continue actions from Alert 2. The Reliability Coordinators and the Energy Deficient Entity shall continue to take all actions initiated during Alert 2. If the emergency has not already been posted on the NERC website (see paragraph 2.1), the respective Reliability Coordinators will, at this time, post on the website information concerning the emergency.

3.2 Declaration Period. The Energy Deficient Entity shall update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the NERC website as changes occur and pass this information on to the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers.

3.3 Use of Transmission short-time limits. The Reliability Coordinators shall request the appropriate Transmission Providers within their Reliability Area to utilize available short-time transmission limits or other emergency operating procedures in order to increase transfer capabilities into the Energy Deficient Entity.

3.4 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator of the Energy Deficient Entity shall evaluate the risks of revising SOLs and IROLs on the reliability of the overall transmission system. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. The resulting increases in transfer capabilities shall only be made available to the Energy Deficient Entity who has requested an Energy Emergency Alert 3 condition. SOLs and IROLs shall only be revised as long as an Alert 3 condition exists or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Energy Deficient Entity obligations. The deficient Balancing Authority or Load Serving Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding.

3.4.2 Mitigation of cascading failures. The Reliability Coordinator shall use its best efforts to ensure that revising SOLs or IROLs would not result in any cascading failures within the Interconnection.

3.5 Returning to pre-emergency Operating Security Limits. Whenever energy is made available to an Energy Deficient Entity such that the transmission systems can be returned to their pre-emergency SOLs or IROLs, the Energy Deficient Entity shall notify its respective Reliability Coordinator and downgrade the alert.

3.5.1 Notification of other parties. Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator shall notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities, and Transmission Providers that their systems can be returned to their normal limits.

3.6 Reporting. Any time an Alert 3 is declared, the Energy Deficient Entity shall submit the report enclosed in this Attachment to its respective Reliability Coordinator within two business days of downgrading or termination of the alert. Upon receiving the report, the Reliability Coordinator shall review it for completeness and immediately forward it to the NERC staff for posting on the NERC website. The Reliability Coordinator shall present this report to the Reliability Coordinator Working Group at its next scheduled meeting.

4. **Alert 0 - Termination.** When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it shall request of its Reliability Coordinator that the EEA be terminated.

4.1. **Notification.** The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the affected Balancing Authorities and Transmission Operators. The Alert 0 shall also be posted on the NERC website if the original alert was so posted.

C. Energy Emergency Alert 3 Report

A Deficient Balancing Authority or Load Serving Entity declaring an Energy Emergency Alert 3 must complete the following report. Upon completion of this report, it is to be sent to the Reliability Coordinator for review within two business days of the incident.

Requesting Balancing Authority:

Entity experiencing energy deficiency (if different from Balancing Authority):

Date/Time Implemented:

Date/Time Released:

Declared Deficiency Amount (MW):

Total energy supplied by other Balancing Authority during the Alert 3 period:

Conditions that precipitated call for "Energy Deficiency Alert 3":

Application Guidelines

If "Energy Deficiency Alert 3" had not been called, would firm load be cut? If no, explain:

Explain what action was taken in each step to avoid calling for "Energy Deficiency Alert 3":

1. **All generation capable of being on line in the time frame of the energy deficiency was on line (including quick start and peaking units) without regard to cost.**

2. **All firm and nonfirm purchases were made regardless of cost.**

3. **All nonfirm sales were recalled within provisions of the sale agreement.**

4. **Interruptible load was curtailed where either advance notice restrictions were met or the interruptible load was considered part of spinning reserve.**

5. **Available load reduction programs were exercised (public appeals, voltage reductions, etc.).**

6. **Operating Reserves being utilized.**

Comments:

Reported By: **Organization:**

Title:

Application Guidelines

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

Standard Development Timeline

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1	November 1, 2006	Adopted by Board of Trustees	Revised
2	November 4, 2010	Adopted by Board of Trustees; Modified R4, R5, R6 and associated VSLs for R2, R4, and R7 to clarify that the requirements don't apply to automatic underfrequency load shedding.	Revised to eliminate redundancies with PRC-006-1
2	May 7, 2012	FERC Order issued approving EOP-003-2 (approval becomes effective July 10, 2012)	
3	TBD	TBD	Five Year Review

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Term: definition.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Load Shedding Plans**

2. **Number:** EOP-003-~~2~~3

3. **Purpose:** A Balancing Authority and Transmission Operator operating with insufficient generation or transmission capacity must have the capability and authority to shed load rather than risk an uncontrolled failure of the Interconnection

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Transmission Operator

5. **Background:**

   Text

B. Requirements and Measures

R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection. *[Violation Risk Factor: High] [Time Horizon:]*

Rationale for R1:

M1. Text

~~**R2.** Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required. *[Violation Risk Factor: High] [Time Horizon:]*~~

Rationale for R2:

~~**M2.** Each Transmission Operator that has or directs the deployment of undervoltage load shedding facilities, shall have and provide upon request, its automatic load shedding plans. (Requirement 2)~~

~~**R3.**~~**R2.** Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities. *[Violation Risk Factor: High] [Time Horizon:]*

Rationale for R3:

~~**M3.**~~**M2.** Text

~~**R4.** A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels. *[Violation Risk Factor: High] [Time Horizon:]*~~

Rationale for R4:

~~**M4.** Text~~

~~**R5.** A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown. *[Violation Risk Factor: High] [Time Horizon:]*~~

Rationale for R5:

~~**M5.** Text~~

~~**R6.** After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load. *[Violation Risk Factor: High] [Time Horizon:]*~~

Rationale for R6:

~~**M6.** Text~~

~~**R7.** The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions. *[Violation Risk Factor: High] [Time Horizon:]*~~

Rationale for R7:

~~R8.~~R3. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency. *[Violation Risk Factor: High] [Time Horizon:]*

Rationale for R8:

~~M8.~~M3. Each Transmission Operator and Balancing Authority shall have and provide upon request its manual load shedding plans that will be used to confirm that it meets Requirement 8. (Part 1)

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

Each Balancing Authority and Transmission Operator shall have its current, in-force load shedding plans.

- If an entity is found non-compliant the entity shall keep information related to the noncompliance until found compliant or for two years plus the current year, whichever is longer.
- Evidence used as part of a triggered investigation shall be retained by the entity being investigated for one year from the date that the investigation is closed, as determined by the Compliance Monitor.
- The Compliance Monitor shall keep the last periodic audit report and all requested and submitted subsequent compliance records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audits

Self-Certifications

Spot Checking

Compliance Violation Investigations

Self-Reporting

Complaints Text

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1		**High**	N/A	N/A	N/A	The Transmission Operator or Balancing Authority failed to shed customer load.
~~**R2**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator did not establish plans for automatic load shedding for undervoltage conditions as directed by the requirement.~~
R3		**High**	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting 5% or less of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 5% up to (and including) 10% of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 10%, up to (and including) 15% or less, of its required entities.	The responsible entity did not coordinate load shedding plans, as directed by the requirement, affecting more than 15% of its required entities.
~~**R4**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator failed to consider at least one of the three elements voltage level, rate of voltage decay, or~~

						~~power flow levels) listed in the requirement.~~
~~**R5**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator or Balancing Authority failed to implement load shedding in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.~~
~~**R6**~~		~~**High**~~	~~N/A~~	~~N/A~~	~~N/A~~	~~The Transmission Operator or Balancing Authority failed to shed additional load after it had separated from the Interconnection when there was insufficient generating capacity to restore system frequency following automatic underfrequency load shedding.~~
~~**R7**~~		~~**High**~~	~~The Transmission Operator did not coordinate automatic undervoltage load~~	~~The Transmission Operator did not coordinate automatic undervoltage load~~	~~The Transmission Operator did not coordinate automatic undervoltage load~~	~~The Transmission Operator did not coordinate automatic undervoltage load~~

			~~shedding with 5% or less of the types of automatic actions described in the Requirement.~~	~~shedding with more than 5% up to (and including) 10% of the types of automatic actions described in the Requirement.~~	~~shedding with more than 10% up to (and including) 15% of the types of automatic actions described in the Requirement.~~	~~shedding with more than 15% of the types of automatic actions described in the Requirement.~~
R8		**High**	N/A	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement.	The responsible entity has plans for manual load shedding but did not have the capability to implement the load shedding, as directed by the requirement.	The responsible entity did not have plans for operator controlled manual load shedding, as directed by the requirement nor had the capability to implement the load shedding, as directed by the requirement.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Guidelines and Technical Basis

Requirement R1:

Requirement R2:

Requirement R3:

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2009-03 Emergency Operations EOP-011-1

Informal Comment Period Now Open through April 28, 2014

Now Available

A 30-day informal comment period for the draft standard **EOP-011-1 – Emergency Operations** (intended to consolidate and replace EOP-001-2.1b, EOP-002-3.1, and EOP-003-2) is open through **8 p.m. Eastern on Monday, April 28, 2014.**

If you have questions please contact Laura Anderson via email or by telephone at (404) 446-9671.

Background information for this project can be found on the project page.

Project 2008-02 Undervoltage Load Shedding (proposed PRC-010-1) is also currently posted for a 30-day informal comment period. Requirements R2, R4, and R7 in EOP-003-2 – Load Shedding Plans is captured in the proposed PRC-010-1. Stakeholders may wish to review both projects with respect to the transition of these requirements. Both projects and their implementation plans are being closely coordinated to ensure that there is no gap or duplication of requirements created by the work of the two teams.

Instructions for Commenting

Please use the electronic form to submit comments on the proposed EOP-011-1. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, or at 404-446-2560.

Individual or group. (34 Responses)
Name (19 Responses)
Organization (19 Responses)
Group Name (15 Responses)
Lead Contact (15 Responses)
Contact Organization (15 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (3 Responses)
Comments (34 Responses)
Question 1 (27 Responses)
Question 1 Comments (31 Responses)
Question 2 (26 Responses)
Question 2 Comments (31 Responses)
Question 3 (25 Responses)
Question 3 Comments (31 Responses)
Question 4 (24 Responses)
Question 4 Comments (31 Responses)
Question 5 (22 Responses)
Question 5 Comments (31 Responses)
Question 6 (27 Responses)
Question 6 Comments (31 Responses)

Individual
Greg Froehling
Rayburn Electric Cooperative
Yes
Yes
No
No
No
No
Individual
Winnie Holden
Public Service Enterprise Group
Yes
Yes
No
No

No
No
Group
Midwest Reliability Organization NERC Standards Review Forum (MRO NSRF)
Russ Mountjoy
Midwest reliability Organization
Yes
No
: NSRF requests that the SAR clarify whether Generator Operators may be assigned responsibility for requirements in this set of standards, and what those responsibilities may be. Although the SAR recommends review of EOP-002 Attachment 1 as it relates to the GOP due to recent BES cold weather events, the draft redline of EOP-002 does not suggest that GOPs be added to the applicability section, and does not propose to alter Attachment 1. NSRF questions whether cold weather preparedness should be addressed in Attachment 1 as the Standards Committee did not approve a cold weather SAR and NERC has issued a guideline tailored to the issue. NSRF recommends that the drafting team include additional information in the SAR on how standard requirements may be altered to apply to GOPs.
No
No
No
Yes
Please note that the NSRF has reviewed EOP-002-4 and R5 should have A threshold of being in an EEA prior to shedding load when not meeting your DCS or BAAL limit.
Individual
David Thorne
Pepco Holdings Inc.
Yes
Yes
No
No
No
Yes
EOP-001-3.3 R2.3 and EOP-003-3-3 R3 appear to be duplicative. Consider eliminating R2.3
Group
ACES Standards Collaborators
Ben Engelby
ACES

Yes
We appreciate the drafting team's efforts in removing unnecessary or redundant requirements from the EOP standards.
Yes
We support the removal of the LSE function from EOP-002.
No
No
No
Yes
We thank the drafting team for applying the 5 year review team's recommendations and the proposal in the SAR to remove requirements that meet Paragraph 81 criteria.
Individual
Michael Falvo
Independent Electricity System Operator
Yes
We generarly agree with the scope proposed in the SAR. However, since the draft standards are also posted, we would offer the following initial comments on the following draft standards: EOP-001-2: We suggest combining R3 and R4. R3 requires each TOP and BA to have an emergency plan and, as a minimum, the plan needs to include the tasks to be coordinated with and among adjacent TOPs and BAs. R4 requires the emergency plan to include the applicable elements in Attachment 1-EOP-001. We do not see the need for having two separate requirements each of which requires the inclusion of certain elements to ensure reliable operations under emergency. Hence, we propose to combine R3 and R4 by requiring each TOP and BA to develop an emergency plan that will include (a) the tasks to be coordinated with and among adjacent TOPs and BAs and (b) applicable elements in Attachment 1. EOP-002-4: We continue to disagree with the removal of R6. The response to comment by the 5-year review team indicates that this removal is consistent with P.81 criteria and the recommendations from the Independent Expert Review Panel Report. We do not believe this is the case since R6 spells out the actions a BA need to take when it is unable to meet DCS whereas the BAL standard (BAL-002, we believe) does not stipulate these actions. It only requires a BA or RSG to meet the DCS. It is conceivable that a BA that fails to meet DCS elect to do nothing (since the requirement is already violated), thus exposing the system to a risk of severe frequency excursion and potential collapse if another resource loss contingency occurs before the required reserve is replenished. We also wish to reiterate our proposal to review whether or not R9 should be removed. In the Comment Report, there is no mention of the concern we raised over the removal of R9 and hence we are unable to determine if the SDT has overlooked our comment, or the SDT decided that the removal of R9 was justified based on specific technical assessment or industry support. As indicated in our previous comment, R9 has several subrequirements some of which could be removed thanks to technology advances and adequate coverage by the e-tag spec and/or other communication protocol. However, there are requirements that still require actions by the responsible entities such as the LSE and the RC, which cannot be replaced by technology or IT tools. We suggest the SDT review this again in developing the next draft of EOP-002-4. EOP-003-3 In the Comment Report, there is no mention of the concern we raised over the removal of R6 in relation to R1. We thus wish to reiterate our proposal to review and revise R1 given that R6 will be removed. R6 as written addresses frequency problems and the results of UFLS operations only. R1 as written does not make this distinction, and it asks for load shedding – automatic and/or manual, to address transmission and resource problems. Without R6 and without revising R1, Responsible Entities may simply rely on automatic load shedding schemes (UFLS and UVLS) to address transmission and resource concerns without taking the next steps to implement manual load shedding after the automatic load shedding operations. We suggest the SDT to review the scope of R1, and revise it as

necessary to cover both transmission and resource aspects using automatic and manual load shedding as remedial measures.
Yes
No
Yes
The proposed removal of Requirement R9 of EOP-002 may result in a need to introduce certain business practices in the NAESB standards, especially those subrequirements in R9 that address elevating transmission service priority under emergency. Please also see our comments under Q2, above, that raise a concern over the complete removal of R9.
No
No
Individual
Scott McGough
Georgia System Operations
Yes
No
These standards should not be applicable to LSEs. Possibly its an oversight that the redlined version of EOP-002-4 has LSEs removed; however the SAR still has reference to LSE?
Yes
There were no questions about the drafted revisions to the standards - only about the SAR. Will there be a comment period for the standards (assuming the SAR gets approved)?
Group
Dominion
Randi Heise
Dominion
Yes
No
The LSE has been removed from EOP-002-3.1, and since there are no remaining responsibilities for the LSE, Dominion suggests removing LSE from the SAR.
No
No
No
No
Individual

Anthony Jablonski
ReliabilityFirst
Yes
1. Within the comment form introduction text, it was noted that the FYRT recommended that the EOP SDT consider two specific changes (1 - EOP-001-2.1b, Requirements R1 and R8 should be considered for combination and 2 - The EOP FYRT recommended merging EOP-001-2.1b and EOP-002-3.1 into a single standard) , though the redlined versions of the two standards do not reflect these recommendations. ReliabilityFirst requests clarification on why these two recommendations were not included in the draft redlined versions.
Yes
No
No
No
Yes
2. ReliabilityFirst recommends that a document be developed explaining the rationale behind each of the individual changes being proposed. For example, if an entire requirement is being removed, the associated rationale should be provided so industry will know exactly what facilitated the proposed change (e.g., was the change facilitated by the FYRP, IERP, Paragraph 81 criteria, FERC Directive, etc.). If this rational can be provided to industry prior to formal posting, it will give industry context on the basis of the changes, hence proactively eliminating a number of questions on the front end. ReliabilityFirst understands this current comment period is strictly for the SAR, but would like to have this comment supplied to the forthcoming SDT if this effort moves forward.
Individual
Thomas Foltz
American Electric Power
No
The future SDT needs to map the Attachment 1 Elements in EOP-001 to the requirements for a specific applicable NERC Entity. EOP-001 R4 uses the term “applicable” but this needs to be more concise and mapped to the appropriate NERC Entity as a requirement instead of an Attachment.
No
It appears that LSE is being removed from the standards as an applicable entity. Does removal of a functional entity dictate that it be noted in the SAR’s applicable entity section? If not, what is the purpose of having it selected?
No
Yes
This standard needs to be flexible enough to accommodate the various arragements and responsibilities that exist within the various RTO’s and other hierarchies. EOP-001-3 R1: The requirement does not specify the Transmission Operator, but M1 does. Attachment 1 * Not every single element listed would always apply to both the BA and TOP. This attachment might be made more clear if it could somehow be segmented by Functional Entity applicability. In addition, this list of elements is highly prescriptive. We also suggest simplifying the list. * Element 11: The drafting team needs to explicitly address whether or not windfarms are in scope. EOP-002-4 R5: Failing to comply with control-based requirements such as CPS and DCS, though important, may not

necessitate the prescribed actions in 5.1 and 5.2 in all circumstances. These generally require you to get within a bounds within a prescribed time, and though the entity may be taking action, it may not be in the timeliness prescribed. As currently written, this requirement would require declaring an EEA event or shedding load even when other viable options are still available. Attachment 1, Alert 2 Section For public appeals to be effective, they need to be released sooner rather than later. Since Public Appeals take some time to be effective at reducing load, we feel that Public Appeals need to be called sooner than the EEA2 level. EOP-003-3 R2 – Undervoltage load shedding should be added as an exclusion in addition to automatic under-frequency load shedding .
Group
Florida Municipal Power Agency
Frank Gaffney
Florida Municipal Power Agency
Yes
The scope is appropriate, but the effort needs to be comprehensive and assure that duplication is fully addressed across these three specifc standards, plus the remainder of the EOP standards along with others as appropriate. There were numerous comments in the 5 year review that raised this concern and it appears that many of those comments were addressed. But as an example, the redlined standards still appear to address load shedding in both EOP 001 R2 2.3 and EOP 003.
No
a. EOP 001 R2 2.1 should not apply to TOPs. b. EOP 002 R1 is being eliminated, yet this requirement provides the BA clear decision making authority. c. EOP 003 should become a TOP-only standard for manual load shedding since load shedding for BA's is really only for capacity/energy emergencies and should be a part of EOP 002.
No
No
No
No
Individual
Richard Vine
California ISO
Agree
ISO/RTO Standards Review Committee
Individual
Kathleen Goodman
ISO New England Inc.
Agree
IRC SRC
Group
PacifiCorp
Ryan Millard
PacifiCorp
Yes
Yes

Yes
No
No
No
Individual
Andrew Gallo
City of Austin dba Austin Energy
Yes
Yes
No
No
No
Yes
City of Austin dba Austin Energy (AE) supports the efforts of the SAR SDT. Regarding the redlined standards, AE suggests the following: (1) Consider identifying which items in Attachment 1-EOP-001 apply to TOPs and which apply to BAs. (2) Proposed Requirement R2 in EOP-003-3 should likely exclude automatic UVLS plans (similar to the way it currently excludes automatic UFLS plans) if the intent is to leave UVLS items to the PRC standards in Project 2008-02.
Individual
Andrew Z. Pusztai
American Transmission Company, LLc
Yes
Yes
No
No
No
Yes
Editorial Only: On the Unofficial Comment form, it states “EOP-001-2.1b, Requirements R1 and R8 should be considered for combination”. This should be corrected to “EOP-003-2, Requirements R1 and R8 should be considered for combination”. The SAR is correct.
Group
SPP Standards Review Group
Robert Rhodes

Southwest Power Pool
No
We recommend that the drafting team expand their coordination efforts to include all projects which are impacted or have an impact on the set of EOP standards in this package. All of the standards in the Related Standards table in the SAR are either actively under development or have recently been approved by the industry. Close coordination with the changes proposed in those projects is necessary in the development of the EOP standards. For example, BAL-001-2 elimintates CPS2 which is specifically referenced in EOP-002-4.
No
We note the inclusion of the Generator Operator and Load Serving Entity as Applicable Entities in the SAR but yet do not see a requirement in either of the three standards that holds these entities accountable for any action. The Generator Operator is implied in Attachment 1 of EOP-001-3 but there are no specific references to the Generator Operator in the standard. Similarly, the Load-Serving Entity is included in Attachment 1 of EOP-002-4 but has no responsibility in the standard itself. What is the linkage between being referenced, or implied, in an attachment to a standard and being listed as an Applicable Entity in the SAR? We also note that the posted redline of EOP-002-4 indicates the Load-Serving Entity is to be deleted as an Applicable Entity in that standard.
No
Given our limited involvement with the detailed functioning of other regions, we are not aware of any regional variances which may be needed, especially within the Southwest Power Pool.
No
Yes
We believe there are special regulatory requirements for international transactions. If these requirements still exist, they would need to be considered in the development of EOP-001-3 and EOP-002-4.
Yes
EOP-001-3 requires Balancing Authorities to have operating agreements with adjacent, and possibly remote, Balancing Authorities. With the advent of the super BA with vast generating resources, is it necessary to maintain the requirement for these operating agreements? Additionally, the IRO standards give the Reliability Coordinator authority to order delivery of emergency assistance as needed within its Reliability Coordinator footprint. It would appear a requirement to have these operating agreements for sharing emergency assistance is no longer relevant. The comment form does not specifically address the posted redline versions of the standards and it is unclear if the drafting team is actually seeking our comments on those redlines at this time. We wholeheartedly support the effort to revise the existing standards. As a first pass the redlined verisons are an improvement over the exsiting standards but a significant amount of modification is still needed. We look forward to working with the drafting team as this project develops.
Group
Southern Company
Wayne Johnson
Southern Company Services, Operations Compliance
Yes
Yes
No
No

No
Yes
EOP-001 R1 – SERC OC Comments EOP-001-2.1b R1 should eliminate the obligation for BAs to establish "provisions for obtaining emergency assistance from remote BAs." Regardless of the definition of "remote" as addressed in the interpretation, reliability standards do not need to impose a requirement on BAs to pre-arrange sources of emergency assistance from non-adjacent BAs. In fact, adjacency should not be a parameter addressed by the Requirement, as long as adequate delivery arrangements are in place. Comments for EOP-001-3 R2, R2.1, R2.3, R2.3 and EOP-002-4 R1, R2 EOP-002-4 R1 and R2 are redundant with EOP-001-3 R2 and its sub-requirements. The implementation of a set of plans as required by EOP-001-3 R2 mirrors taking action as described in EOP-002-4 R1 and R2. Due to the redundancy we ask the SDT to consider retiring EOP-002-4 R1 and R2. Comments for EOP-002-4 R3 The SDT is asked to consider adding the actions outlined in EOP-002-4 R3 to EOP-001 Attachment. The proposed EOP-002-4 R3 states: "A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load." We propose deleting EOP-002-4 R3 from the standard since adding the actions in EOP-002-4 R3 to EOP-001 Attachment 1 will eliminate the need of listing the actions in EOP-002 R3. EOP-001-3 M2 Comment Measure 2 is unclear and does not appear to correlate to any action required on R2. Measure 2 should be modified to allow the registered entity to make its plans available to the auditors for review. If an entity has experienced an event that warranted using the plan, the entity could demonstrate "implementation". If an entity has not experienced an event, the entity could demonstrate that all TOP / BA operators have been trained on the plans. M2. The Transmission Operator and Balancing Authority shall have its two most recent annual self- assessments available for review by the Regional Reliability Organization at all times. Comments for EOP-002 R5 Pending BAL requirements address CPS and DCS requirements. BAL-002-1a addresses DCS and BAL-001-2 addresses CPS. The way the current draft reads would pose potential issues with complying with the BAL on the "high side." For example, if an entity can not comply with BAL, then shedding load will only intensify the problem. Consequently, we ask that the SDT review the BAL standards to ensure that the BAL and EOP standards are in sync. After reviewing, we suggest the SDT to consider rewording EOP-002 R5 to state: "If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards by implementing the actions in EOP-001 Attachment 1, the Balancing Authority shall: R5.1. Manually shed firm load without delay to return its ACE to zero; and R5.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts." Comments for EOP-003-3 We suggest removing the BA function from EOP-003-3 and making this a TOP requirement only. The BA function is prepared for capacity and energy emergencies in EOP-002-4, which includes the scope of EOP-003-3 for BAs. EOP-003-3 R2, we ask for the SDT to clarify automatic or manual load shedding as stated:"Each Transmission Operator and Balancing Authority shall coordinate load shedding plans among other interconnected Transmission Operators and Balancing Authorities." We suggest that the SDT reword R2 to state: "Each Transmission Operator and Balancing Authority shall coordinate operator controlled manual load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities."
Individual
Bob Thomas
Illinois Municipal Electric Agency
Yes
Yes
No
No

No
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
LG&E and KU Sevices
These comments are submitted on behalf of the following PPL NERC Registered Affiliates (PPL): Louisville Gas and Electric Company and Kentucky Utilities Company; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.
Yes
PPL NERC Registered Affiliates has concerns about the redlined version of EOP-002-3 Requirement R5. The meaning of “comply with the Control Performance and Disturbance Control Standards” is unclear. For example, it could mean that the BA has actually violated the Standards or that it is clear that the BA will violate the Standards. Since it is unknown what the intent of the SME team was when it proposed the change, we cannot suggest proposed language as an alternative.
Group
Bureau of Reclamation
Erika Doot
Power Resources Office
Yes
No
The Bureau of Reclamation (Reclamation) requests that the SAR clarify whether Generator Operators (GOPs) may be assigned responsibility for requirements in this set of standards, and what those responsibilities may be. The SAR indicates that the standards will apply to the GOP function, but the draft redline standards do not include GOPs in the applicability sections. Although the SAR recommends review of Attachment 1 as it relates to the GOP due to recent BES cold weather events, the draft redline does not propose to alter Attachment 1. Reclamation questions whether GOP cold weather preparedness should be addressed in Attachment 1. Reclamation recommends that the drafting team include additional information in the SAR on how standard requirements may be altered to apply to GOPs, and whether this would be limited to cold weather preparedness.
No
No
Group
Duke Energy
Michael Lowman
Duke Energy

Yes
No
Duke Energy questions the need to add LSE and GOP as responsible entities. Neither is listed in EOP-001, EOP-002, or EOP-003 as Applicable Function.
No
No
No
Individual
Bill Fowler
City of Tallahassee (TAL)
Yes
EOP-002-4, Proposed R1 should be a subset of R3. You can meet R1 by taking any one action necessary, but you could still be deficient by not taking all necessary actions per R3. The City of Tallahassee (TAL) recommends adding the elements of R3 to EOP-001-3, Attachment 1. Having elements of an Emergency Plan in 2 different spots is hard to follow and could lead to missed requirements. As written, they do not have to be part of a written plan, but do need to be performed in the anticipated horizon. Table of Compliance Elements is now difficult to follow since it was not refreshed with new requirement numbers. The Heading should be repeated on all pages of the table. Attachment 1 section 3.6 is a reporting requirement. Requirements should not be buried in attachments. TAL questions the necessity of this inclusion given the revised EOP-004-2. Also, Attachment 1 applies to LSEs, but LSEs were removed from the Applicability for this standard. == EOP-003-3, The remaining requirements are duplicative of the requirements in EOP-001-3. EOP-003-1 R1- “After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.” EOP-001-3 R2.3 – “Develop, maintain, and implement a set of plans for load shedding.” EOP-003-3, R2 – “Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.” EOP-001-3, R5 – “The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities. – or – EOP-001-3, R3.3 – “The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities. EOP-003-3, R3 – “Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.” EOP-001-3, R2.3 – “Develop, maintain, and implement a set of plans for load shedding.” If the SDT does not agree the intent or spirit of EOP-003 is captured as described, TAL recommends substantiating EOP-001, and then eliminating EOP-003. Having similar requirements in 2 different standards is contrary to the progress being made with Paragraph 81 and RAIs.

Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
Yes
With regard to EOP-001-2, R3 requires each TOP and BA to have an emergency plan and, as a minimum, the plan needs to include the tasks to be coordinated with and among adjacent TOPs and BAs. R4 requires the emergency plan to include the applicable elements in Attachment 1-EOP-001. There is no need for having two separate requirements each of which requiring the inclusion of certain elements to ensure reliable emergency operations. Propose to combine R3 and R4 by requiring each TOP and BA to develop an emergency plan that will include the tasks to be coordinated with and among adjacent TOPs and BAs and applicable elements in Attachment 1. Regarding EOP-002-4, we disagree with the removal of R6. The response to comments by the 5-year review team indicates that this removal is consistent with P81 criteria, and the recommendations from the Independent Expert Review Panel Report. This is not the case since R6 spells out the actions a BA need to take when it is unable to meet DCS whereas the BAL standard (BAL-002) does not stipulate these actions. It only requires a BA or RSG to meet the DCS. It is conceivable that a BA that fails to meet DCS can elect to do nothing (since the requirement is already violated), thus exposing the system to a risk of a severe frequency excursion and potential collapse if another resource contingency occurs before the required reserve is replenished. The removal of R9 should be reconsidered by the SDT. R9 has several parts, some of which could be removed because of technological advances and adequate coverage by the e-tag spec and/or other communication protocols. Part 9.1 should be retained because it still requires actions by the responsible entities such as the LSE and the RC, which cannot be replaced by technology or IT tools. The SDT should consider retaining the concept of Part 9.1. Regarding EOP-003-3, given that R6 will be removed, review and revise R1. R6 as written addresses frequency problems and the results of UFLS operations only. R1 as written does not make this distinction, and it asks for load shedding – automatic and/or manual, to address transmission and resource problems. Without R6 and without revising R1, Responsible Entities may simply rely on automatic load shedding schemes (UFLS and UVLS) to address transmission and resource concerns without taking the next steps to implement manual load shedding after the automatic load shedding operations. We suggest the SDT to review the scope of R1, and revise it as necessary to cover both transmission and resource aspects using automatic and manual load shedding as remedial measures.
Yes
No
Yes
The proposed removal of Requirement R9 of EOP-002 may result in a need to introduce certain business practices in the NAESB standards, especially those parts of R9 that address elevating transmission service priority in an emergency. Refer to our comments to Question 2 above that raise a concern over the complete removal of R9.
No
Individual
Joe O'Brien on behalf of David Austin
NIPSCO
Yes
Yes

No
No
No
Yes
EOP-001 I would suggest moving R2.3 into EP-003. R3 seems redundant with R2 and should be removed altogether. The remaining sub-requirement R3.3 should be merged with the existing R4 to read: "R3 Each Transmission Operator and Balancing Authority shall include the tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities, in addition to the applicable elements in Attachment 1-EOP-001, when developing an emergency plan." In an effort to remove some of the redundancy from the standards, R4 should specify which emergency plans it applies to, namely those identified in R2. From the way the requirement currently reads, this could technically apply to emergency plans developed in EOP-003 and EOP-005. EOP-002 I agree with all the proposed changes. EOP-003 I agree with all the proposed changes, with the proposed addition suggested above.
Individual
Scott Langston
City of Tallahassee
Yes
EOP-002-4, Proposed R1 should be a subset of R3. You can meet R1 by taking any one action necessary, but you could still be deficient by not taking all necessary actions per R3. The City of Tallahassee (TAL) recommends adding the elements of R3 to EOP-001-3, Attachment 1. Having elements of an Emergency Plan in 2 different spots is hard to follow and could lead to missed requirements. As written, they do not have to be part of a written plan, but do need to be performed in the anticipated horizon. Table of Compliance Elements is now difficult to follow since it was not refreshed with new requirement numbers. The Heading should be repeated on all pages of the table. Attachment 1 section 3.6 is a reporting requirement. Requirements should not be buried in attachments. TAL questions the necessity of this inclusion given the revised EOP-004-2. Also, Attachment 1 applies to LSEs, but LSEs were removed from the Applicability for this standard. EOP-003-3, The remaining requirements are duplicative of the requirements in EOP-001-3. EOP-003-1, R1- “After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.” EOP-001-3 R2.3 – “Develop, maintain, and implement a set of plans for load shedding.” EOP-003-3, R2 – “Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.” EOP-001-3, R5 – “The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities. – or – EOP-001-3, R3.3 – “The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities. EOP-003-3, R3 – “Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.” EOP-001-3, R2.3 – “Develop, maintain, and implement a set of plans for load shedding.” If the SDT does not agree the intent or spirit of EOP-003 is

captured as described, TAL recommends substantiating EOP-001, and then eliminating EOP-003. Having similar requirements in 2 different standards is contrary to the progress being made with Paragraph 81 and RAIs.
Group
Tacoma Power
Chang Choi
Tacoma Power
Yes
Yes
No
No
No
Yes
EOP-002, R5.1 & R5.2 should be swapped due to the order that a BA must actually proceed. Also remedies that existed in the previous version R6 should have been retained and preceded the new R5.1 & R5.2 rather than being deleted entirely in this draft.
Group
MRO NERC Standards Review Forum
Russel Mountjoy
MRO
Yes
NSRF requests that the SAR clarify whether Generator Operators may be assigned responsibility for requirements in this set of standards, and what those responsibilities may be. Although the SAR recommends review of EOP-001 Attachment 1 as it relates to the GOP due to recent BES cold weather events, the draft redline of EOP-001 does not suggest that GOPs be added to the applicability section, and does not propose to alter Attachment 1. NSRF questions whether cold weather preparedness should be addressed in Attachment 1 as the Standards Committee did not approve a cold weather SAR and NERC has issued a guideline tailored to the issue. NSRF recommends that the drafting team include additional information in the SAR on how standard requirements may be altered to apply to GOPs.
The Standards Committee recently rejected a SAR that proposed a standard on cold weather preparedness. The Standards Committee decision was that the recently prepared NERC guideline on cold weather preparedness was adequate and that a standard was not needed. Based on this decision, the references to cold weather preparedness should not be included in these standards (e.g. in item 10 of attachment 1 of EOP-001-3)
Group
ISO/RTO Council Standards Review Committee
Greg Campoli
NYISO

Yes
We generally agree with the scope proposed in the SAR. However, since the draft standards are also posted, we would offer the following initial comments on the following draft standards: EOP-001-2: The word “adjacent” should be capitalized since Adjacent Balancing Authority is a defined term in the NERC Glossary. R1 does not have TOP as a Responsible Entity but M1 requires a TOP to provide evidence. Please review and resolve the discrepancy. R2 requires BAs to have plans to mitigate emergencies on the transmission system, but BAs have no obligation to model said transmission system. If BAs are required to have such plans, then the planned actions should be directed/requested by the TOPs. This needs to be made clear in the requirement. R2 requires the development of plans, not annual assessments, but Measure M2 requires that the last two annual assessments be available for review. Further, the evidence retention for R1, R2, R4 and R5 requires the most recent 3 calendar months plus the current month, which is consistent with the M2 evidence requirement for annual assessments/plans. Suggest to review and revise R2 and/or Measure M2 and/or the retention requirement for R2. We suggest combining R3 and R4. R3 requires each TOP and BA to have an emergency plan and, as a minimum, the plan needs to include the tasks to be coordinated with and among adjacent TOPs and BAs. R4 requires the emergency plan to include the applicable elements in Attachment 1-EOP-001. We do not see the need for having two separate requirements each of which requires the inclusion of certain elements to ensure reliable operations under emergency. Hence, we propose to combine R3 and R4 by requiring each TOP and BA to develop an emergency plan that will include (a) the tasks to be coordinated with and among adjacent TOPs and BAs and (b) applicable elements in Attachment 1. Measure M5 is missing. It needs to be a Measure that is needed to demonstrate that the TOP and BA have annually reviewed and updated each emergency plan. EOP-002-4: We appreciate the SDT’s effort to retain the previous Requirement R6, now R5. However, a number of the optional actions listed in the previous R6 have been removed, resulting in only two actions – shedding firm load and declaring EEA to address a reserve/capacity shortfall after a BA fails to meet CPS and DCS requirements. We do not believe removing the other actions such as loading all available generation, curtail interruptible loads, etc. is helpful to reliability, nor do we believe that such actions are already presented in other standards to warrant them meeting the Paragraph 81 criteria. It is conceivable that a BA that fails to meet DCS elects to take none of these actions but just dive into shedding firm load. While shedding firm load may be the last resort to address a capacity shortfall, it is a general practice, and a prudent and rational one, to not shed firm load in a reserve shortfall (which may be the result of an MSSC event) until the actual capacity shortage occurs after the next resource contingency (in other words, why shed firm load for the sake of avoiding shedding firm load when a resource contingency occurs). We therefore once again suggest that the removed actions be re-inserted to R5. We also wish to reiterate our proposal to review whether or not R9 should be removed. In the Comment Report, there is no mention of the concern we raised over the removal of R9 and hence we are unable to determine if the SDT has overlooked our comment, or the SDT decided that the removal of R9 was justified based on specific technical assessment or industry support. As indicated in our previous comment, R9 has several sub-requirements some of which could be removed thanks to technology advances and adequate coverage by the e-tag spec and/or other communication protocol. However, there are requirements that still require actions by the responsible entities such as the LSE and the RC, which cannot be replaced by technology or IT tools. We suggest the SDT review this again in developing the next draft of EOP-002-4. EOP-003-3 R2: We suggest to replace “interconnected” with “Adjacent” since TOPs and BAs are all interconnected – directly or remotely. Leaving the word “interconnected” in place would mean these entities need to coordinate with all entities in an interconnection. R3: We suggest to drop the second sentence since the “capability” of an entity to shed firm load in response to an emergency is not measurable in a plan; it can only be measured when actions are taken to address an actual emergency. In the Comment Report, there is no mention of the concern we raised over the removal of R6 in relation to R1. We thus wish to reiterate our proposal to review and revise R1 given that R6 will be removed. R6 as written addresses frequency problems and the results of UFLS operations only. R1 as written does not make this distinction, and it asks for load shedding – automatic and/or manual, to address transmission and resource problems. Without R6 and without revising R1, Responsible Entities may simply rely on automatic load shedding schemes (UFLS and UVLS) to address transmission and resource concerns without taking the next steps to implement manual load shedding after the automatic load shedding operations. We suggest the SDT to review the scope of R1, and revise it as necessary to cover both

transmission and resource aspects using automatic and manual load shedding as remedial measures.
Yes
No
Yes
The proposed removal of Requirement R9 of EOP-002 may result in a need to introduce certain business practices in the NAESB standards, especially those sub-requirements in R9 that address elevating transmission service priority under emergency.
No
No
Individual
Karen Webb
City of Tallahassee - Electric Utility
Yes
EOP-002-4: Proposed R1 should be a subset of R3. You can meet R1 by taking any one action necessary, but you could still be deficient by not taking all necessary actions per R3. The City of Tallahassee (TAL) recommends adding the elements of R3 to EOP-001-3, Attachment 1. Having elements of an Emergency Plan in 2 different spots is hard to follow and could lead to missed requirements. As written, they do not have to be part of a written plan, but do need to be performed in the anticipated horizon. Table of Compliance Elements is now difficult to follow since it was not refreshed with new requirement numbers. The heading should be repeated on all pages of the table. Attachment 1 section 3.6 is a reporting requirement. Requirements should not be buried in attachments. TAL questions the necessity of this inclusion given the revised EOP-004-2. Also, Attachment 1 applies to LSEs, but LSEs were removed from the Applicability for this standard. EOP-003-3: The remaining requirements are duplicative of the requirements in EOP-001-3. EOP-003-1 R1- “After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.” EOP-001-3 R2.3 – “Develop, maintain, and implement a set of plans for load shedding.” EOP-003-3, R2 – “Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.” EOP-001-3, R5 – “The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities. – or – EOP-001-3, R3.3 – “The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities. EOP-003-3, R3 – “Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.” EOP-001-3, R2.3 – “Develop, maintain, and implement a set of plans for load shedding.” If the SDT does not agree the intent or spirit of EOP-003 is captured as described, TAL recommends substantiating EOP-001, and then eliminating EOP-003.

Having similar requirements in 2 different standards is contrary to the progress being made with Paragraph 81 and RAIs.
Individual
Chris Scanlon
Exelon Companies
Yes
Yes
No
No
No
Yes
Exelon and its affiliates appreciate the work done by the drafting team for Project 2009-03 and will vote Affirmative on this ballot.
Individual
Doug Hohlbaugh
FirstEnergy
Yes
Yes
No
No
No
No
Group
Bonneville Power Administration
Jamison Dye
Transmission Reliability Standards Group
Yes
Yes
No
No
No

Yes
a) EOP-002: BPA agrees that the industry needs standards that are technically accurate and support the overall goal of ensuring bulk power system reliability. For the applicable entities to effectively comply, measurable and enforceable standards must be reasonable, clear, and unambiguous; thereby, minimizing the need for interpretation. Users, owners, and operators of the bulk power system should have no doubts with regards to what is required and who it is required of. Previous requirements, R6 and R7, for example, stated that entities should complete certain perquisites to alleviate resources (R6) and after exhausting all those options, operators should manually shed load (R7). With the new R5 requirement, preceding required actions have been removed. BPA feels that requiring operators to shed load for a CPS problem is too severe of an action; however, BPA does feel that shedding load for a DCS issue is acceptable. BPA maintains that since preliminary actions (from previous requirements) have been removed, then NERC needs to emphasize in the new requirement that when entities do not meet CPS and DCS (both conditions must exist), that, in turn, could result in load shedding or schedule cuts. b) EOP=001: R1 says that we are supposed to have agreements with “adjacents” for emergency assistance and that BAs are also supposed to include in their agreements with adjacents provisions which allow the BA to obtain emergency assistance from “remote adjacents.” The Appendix 1 responses for requirement 1 indicate — in spite of the fact that a BA may have an agreement with an adjacent for emergency assistance — that the adjacent BA, in turn, does not have to have a corresponding provision with a remote adjacent to share resources. BPA feels that the adjacent should have a provision to allow for this kind of sharing of resources — if you have an agreement with a remote, then you must have a provision so stating this mutual assistance.
Individual
Alice Ireland
Xcel Energy
Agree
SPP RTO

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. SC authorized moving the SAR forward to standard development 10/17/2013.
2. SAR posted for comment 11/06/13-12/05/13.

Description of Current Draft

This is the first draft of the proposed standard and is being posted for informal stakeholder comments. This draft includes the modifications based on the Five-Year Review Team recommendations, comments submitted by stakeholders during the SAR comment period, as well as other items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
30-day Informal Comment Period	March 2014
45-day Formal Comment Period with Parallel Initial Ballot	June 2014
Final ballot	September 2014
BOT adoption	November 2014
File standard with regulatory authorities	December 2014

Effective Dates

The standard shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Initial Standard	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Energy Emergency - A condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide its ~~customers'~~ expected ~~energy~~ Load requirements.

The proposed revisions are intended to clarify that an Energy Emergency is not necessarily limited to a Load-Serving Entity. This term, or variations of it, is also used in other standards, as indicated below. The EOP SDT does not believe the proposed revisions change the reliability intent of requirements or definitions.

BAL-002-WECC-2 – Contingency Reserve

R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is: *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*

1.1. The greater of either:

- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

1.2. Comprised of any combination of the reserve types specified below:

- Operating Reserve – Spinning
- Operating Reserve - Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve – Supplemental
- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service
- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.

1.3. Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).

1.4 An amount of capacity from a resource that is deployable within ten minutes.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-1**

3. **Purpose:** To mitigate the effects of operating Emergencies, up to and including manual Load shedding, by ensuring each Transmission Operator and Balancing Authority has developed Emergency Operating Plans, and those plans are coordinated within a Reliability Coordinator Area.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

5. **Background:**

EOP-011-1 is a new standard that consolidates requirements from three existing Emergency Operations standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

The Project 2009-03 Emergency Operations Standard Drafting Team (EOP SDT) developed EOP-011-1 by considering the following inputs:

- Applicable FERC directives;
- Five Year Review Team (FYRT) recommendations;
- Independent Expert Review Panel recommendations; and
- Paragraph 81 criteria.

The purpose of EOP-011-1 is to mitigate the effects of operating Emergencies, up to and including manual Load shedding, by implementing Emergency Operating Plans. The standard streamlines the requirements for Emergency Operations for the BES into a clearer and more concise standard that is organized by Functional Entity in order to eliminate the ambiguity in previous versions. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include the following elements: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]*

1.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan.

1.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum:

1.2.1. Plans to control voltage;

1.2.2. Processes for cancelling or recalling Transmission outages;

1.2.3. Processes for System reconfiguration;

1.2.4. Processes for redispatch of generation;

1.2.5. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding;

1.2.6. Strategies to be used to mitigate reliability impacts of extreme weather conditions.

1.3. A process for revising its Emergency Operating Plan to account for changes in its System.

Rationale for R1: The EOP SDT examined the recommendation of the EOP FYRT and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment, 1 and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Transmission Operator to create an Emergency Operating Plan.

Requirement 1.2.1 was added to this standard for the Transmission Operator to address procedures, processes or strategies to prepare for and mitigate Emergencies using voltage control methods, which could include switching of capacitor and reactor banks, generator reactive output and the use of synchronous condensers.

The topic of manual Load shedding is included in Requirement R1 (Transmission Operator Emergency Operating Plan) and Requirement R2 (Balancing Authority Emergency Operating Plan) because this sometimes requires coordination between the Balancing Authority and Transmission Operator.

The EOP SDT added Requirement R1.3, a revision of Requirement R5 in EOP-001-2.1b, to establish a process for the Transmission Operator to revise its Emergency Operating Plan to account for changes in its System.

M1. Each Transmission Operator will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R1that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability

Coordinator; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]*

2.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan.

2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum:

2.2.1. Generating resources in its Balancing Authority Area:

2.2.1.1. capability and availability;

2.2.1.2. fuel supply and inventory concerns;

2.2.1.3. fuel switching capabilities;

2.2.1.4. environmental constraints.

2.2.2. Voluntary Load reductions;

2.2.3. Public appeals;

2.2.4. Governmental programs;

2.2.5. Reduction of internal utility energy use;

2.2.6. Customer fuel switching;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding;

2.2.9. Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan.

2.3. A process for revising its Emergency Operating Plan to account for changes in its System.

Rationale for R2: The EOP SDT took the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1. The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Balancing Authority to create its Emergency Operating Plan to address capacity and energy Emergencies.

Manual Load shedding is included in Requirement R1 (Transmission Operator Emergency Operating Plan) and Requirement R2 (Balancing Authority Emergency Operating Plan) because this sometimes requires coordination between the Balancing Authority and Transmission Operator.

The EOP SDT added Requirement R2.3, a revision of Requirement R5 in EOP-001-2.1b, to establish a process for the Balancing Authority to revise its Emergency Operating Plan to account for changes in its System.

M2. Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R2.

R3. Each Reliability Coordinator shall coordinate the Emergency Operating Plans of the entities in its Reliability Coordinator Area to ensure that the plans are compatible and support reliability in the Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Rationale for R3: The EOP SDT agrees that Transmission Operators and Balancing Authorities should submit Emergency Operating plans to the Reliability Coordinator for approval in order for the Reliability Coordinator to ensure all Emergency Operating Plans in its Reliability Coordinator Area are coordinated and compatible. This requirement makes the standard applicable to the Reliability Coordinator; clearly and separately identifying the Transmission Operator, Balancing Authority and Reliability Coordinator issues as they relate to the Balancing Authority and Transmission Operator (to address Paragraph 548 of Order 693) and how it needs to be planned for on the BES by the specific Functional Entities.

"…the Commission finds the reliability coordinator is a necessary entity under EOP-001-0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity."

M3. The Reliability Coordinator will have, and provide upon request, evidence that could include, but is not limited to, dated review documents, electronic records or studies that it coordinated each Transmission Operator's and Balancing Authority's Emergency Operating Plans within its Reliability Coordinator Area to ensure that the plans are compatible in accordance with Requirement R3.

R4. Each Reliability Coordinator shall approve or disapprove, with stated reasons for disapproval, Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans within 30 calendar days of submittal. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Rationale for R4: Since Requirements R1 and R2 both require a submittal for approval, Requirement R4 requires approval or disproval. This aligns with similar requirements in EOP-006-2, Requirement 5.1.

M4. The Reliability Coordinator will have documentation, such as e-mails with receipts or registered mail receipts that it approved or disapproved, with stated reasons for disapproval, the Transmission Operator and Balancing Authority submitted and revised Emergency Operating Plans within 30 calendar days of submittal in accordance with Requirement R4.

R5. Each Transmission Operator that is experiencing an operating Emergency on its Transmission System shall communicate the Emergency and its current and projected System conditions to its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R5: This was an existing requirement in EOP-002-3.1 for Balancing Authorities. The EOP SDT has added this as an additional requirement for Transmission Operators. The EOP SDT revised communication of “future system conditions” to “projected system conditions.” The purpose of this requirement is to apprise the Reliability Coordinator of the Transmission Operator’s Real-time operations preparation and planning.

M5. The Transmission Operator that experienced an operating Emergency on its Transmission System will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it communicated the Emergency and its current and projected System conditions to its Reliability Coordinator in accordance with Requirement R5.

R6. Each Balancing Authority that is experiencing a capacity or Energy Emergency shall communicate the Emergency and its current and projected System conditions to its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R6: This was an existing requirement in EOP-002-3.1 for Balancing Authorities. The EOP SDT revised communication of “future system conditions” to “projected system conditions.” This modification is intended to apprise the Reliability Coordinator of the Balancing Authority Real-time operations preparation and planning.

M6. The Balancing Authority that experienced a capacity or Energy Emergency will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it communicated the Emergency and its current and projected System conditions to its Reliability Coordinator in accordance with Requirement R6.

R7. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as practicable, impacted Reliability Coordinators, Balancing Authorities and Transmission Operators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R7: The EOP SDT added the words "as soon as practicable" to the requirement to point to the timeliness and to the relevancy of the Emergencies and to alleviate excessive notifications on Balancing Authorities and Transmission Operators. This was an existing requirement in EOP-002-3.1 for Balancing Authorities.

M7. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it communicated the Balancing Authority's or Transmission Operator's Emergency to impacted Reliability Coordinators, Balancing Authorities and Transmission Operators in accordance with Requirement R7.

R8. The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert after the Balancing Authority has performed the steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R8: The EOP SDT placed this language in this requirement since it was found in Requirements R6.5 and R7.2 of E0P-002-3.1. The EOP SDT agrees that manual Load shedding and other actions are addressed in the Emergency Operating Plan and it is not necessary to explicitly call for Load shedding to return ACE to zero in this standard. ACE requirements for the Balancing Authority are addressed in the BAL-001 and BAL-002 standards.

M8. Each Balancing Authority who, after performing the steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition, will have and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that it requested its Reliability Coordinator to declare a NERC Energy Emergency Alert in accordance with Requirement R8.

R9. Each Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate a NERC Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R9: The EOP SDT retained Requirement R8 from E0P-002-3.1. The Load-Serving Entity has the right, under Attachment 1, to request that an Energy Emergency Alert (EEA) be issued, but it does not have any requirements to do so; therefore, the EOP SDT elected to retain the Load-Serving Entity in the requirement, but not as an applicable entity. If it becomes a reliability issue, the Balancing Authority or Reliability Coordinator will call for the EEA.

M9. Each Reliability Coordinator, that has had a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that it initiated a NERC Energy Emergency Alert, as detailed in Attachment 1 in accordance with Requirement R9.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

Regional Entity

1.2. Evidence Retention

The Balancing Authority, Reliability Coordinator, and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall retain the current Emergency Operating Plan, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R2, and Measure M2.

- The Balancing Authority shall maintain evidence of compliance since the last audit for Requirements R6 and R8 and Measures M6 and M8.

- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R4, R7 and R9 and Measures M3, M4, M7 and M9.

- The Transmission Operator shall retain the current Emergency Operating Plan, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R1, and Measure M1.

- The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R5 and Measure M5.

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

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**TBD**					
R2	**TBD**					
R3	**TBD**					
R4	**TBD**					
R5	**TBD**					
R6	**TBD**					
R7	**TBD**					
R8	**TBD**					
R9	**TBD**					

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Attachment 1-EOP-011-1
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority or Load-Serving Entity in its authority which is experiencing an Energy Emergency.

The Load-Serving Entity or Balancing Authority who requests this assistance is referred to as an "Energy Deficient Entity."

NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of the Energy Deficient Entity.
2. **Notification**. A Reliability Coordinator who declares an Energy Emergency Alert should notify all Balancing Authorities and Transmission Operators in its reliability area. The Reliability Coordinator should also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators should be held as necessary to communicate System conditions. The Reliability Coordinator should also notify the other Reliability Coordinators, Balancing Authorities and Transmission Operators when the alert has ended.

B. Energy Emergency Alert Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining Energy Emergencies to each other. An Energy Emergency Alert is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **Alert 1 — Forecast the need for an Energy Emergency.**

Circumstances:

- Energy Deficient Entity foresees the need to issue alerts in the upcoming operating window and is concerned about Operating Reserves.

2. Alert 2 — All available resources in use.

Circumstances:

- Energy Deficient Entity is experiencing conditions where all available resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves.

3. Alert 3 — Load management procedures in effect.

Circumstances:

- Energy Deficient Entity is no longer able to provide its customers' expected energy requirements.
- Energy Deficient Entity has implemented its approved Emergency Operations Plan.

During Alert 3, Reliability Coordinators, Balancing Authorities and Energy Deficient Entities have the following responsibilities:

3.1 Notifying other Balancing Authorities and market participants. The Energy Deficient Entity should communicate its needs to other Balancing Authorities and market participants. Upon request from the Energy Deficient Entity, the respective Reliability Coordinator should post the declaration of the alert level, along with the name of the Energy Deficient Entity and, if applicable, its Balancing Authority on the RCIS website.

3.2 Declaration period. The Energy Deficient Entity should update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 3 is terminated. The Reliability Coordinator should update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the affected Reliability Coordinators, Balancing Authority and Transmission Providers**.**

3.3 Sharing information on resource availability. A Balancing Authority with available resources should contact the Energy Deficient Entity and coordinate with the Reliability Coordinator as appropriate.

3.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator should review Transmission outages and work with the Transmission Operator to see if it's possible to return the Transmission element that may relieve the Loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

3.5 Energy Deficient Entity actions. Before declaring an Alert 4, the Energy Deficient Entity must make use of all available resources; this includes, but is not limited to:

3.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line, including quick-start and peaking units, regardless of cost.

3.5.2 Initiate contractually interruptible Loads and demand-side management curtailed. Initiate contractually interruptible retail Loads curtailed, and demand-side management activated within provisions of the agreements.

3.5.3 Operating Reserves. Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program.

Alert 4 — Firm Load interruption imminent or in progress.

Circumstances:

- Energy Deficient Entity foresees or has implemented firm Load obligation interruption.

4.1 Continue actions from Alert 3. The Reliability Coordinators and the Energy Deficient Entity should continue to take all actions initiated during Alert 3.

4.2 Declaration Period. The Energy Deficient Entity should update its Reliability Coordinator of the situation at a minimum of every hour until the Alert 4 is terminated. The Reliability Coordinator should update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the affected Balancing Authorities and Transmission Providers.

4.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator should evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the Energy Deficient Entity. Reevaluation of SOLs and IROLs should be coordinated with other Reliability Coordinators and only with the agreement of the Balancing Authority or Transmission Operator whose equipment would be affected. SOLs and IROLs should only be revised as long as an Alert 4 condition exists, or as allowed by the Balancing Authority or Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

4.3.1 Energy Deficient Entity obligations. The Energy Deficient Entity must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

4.4 Returning to pre-Emergency conditions. Whenever energy is made available to an Energy Deficient Entity such that the Transmission Systems can be returned to its pre-Emergency SOLs or IROLs, the Energy Deficient Entity should notify its respective Reliability Coordinator and downgrade the alert.

4.4.1 Notification of other parties. Upon notification from the Energy Deficient Entity that an alert has been downgraded, the Reliability Coordinator should notify the affected Reliability Coordinators (via the RCIS), Balancing Authorities and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it should request of its Reliability Coordinator that the EEA be terminated**.**

0.1 Notification. The Reliability Coordinator should notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator should also notify the affected Balancing Authorities and Transmission Operators.

Guidelines and Technical Basis

Rationales to be added here after balloting.

Requirement R1:

Requirement R2:

Requirement R3:

Requirement R4:

Requirement R5:

Requirement R6:

Requirement R7:

Requirement R8:

Requirement R9:

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Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Emergency Operations (EOP-001-3, EOP-002-4, EOP-003-3)		
Date Submitted:	October 17, 2013		
SAR Requester Information			
Name:	David McRee, Chair EOP Five-Year Review Team (FYRT)		
Organization:	Duke Energy		
Telephone:	(704) 382-9841	E-mail:	David.McRee@duke-energy.com
SAR Type (Check as many as applicable)			
☐ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
This SAR will address the Five-Year Review requirement for these standards.
Purpose or Goal (How does this request propose to address the problem described above?):
To improve the quality, relevance, and clarity of the standards. Also bring the standards into the Results Based Standards format.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
To increase the effectiveness of the three standards in their ability to ensure reliability of the BES.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The EOP SDT will consider the comments received from the EOP Five Year Review Team (FYRT), which includes consideration of industry comments and the report from the Industry Expert Review Panel. Recommendations for consideration are: • Modify the requirements and attachments to improve their clarity and measurability, while removing ambiguity • Move and/or streamline requirements • Eliminate requirements based on P81 criteria • Coordinate with Project 2008-02 UVLS to eliminate duplicative requirements • Apply Paragraph 81 criteria and recommendations from Independent Expert Review Panel on standards EOP-001, -002, and -003. To ensure a seamless transition from the EOP FYRT to the future EOP SDT, the EOP FYRT recommends the inclusion of interested EOP FYRT members to participate on the EOP SDT. In addition, the EOP FYRT should provide a high-level overview of their recommendations as a formal kick-off to the future EOP SDT meetings.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
See the attached Five-Year Review templates of the three standards, consideration of comments, issues and directives list, redlined standards (reflecting deletions), and the Industry Experts' anyalsis.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☒ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

Reliability Functions	
☒ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.
☒ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐ Distribution Provider	Delivers electrical energy to the End-use customer.
☐ Generator Owner	Owns and maintains generation facilities.
☒ Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐ Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐ Market Operator	Interface point for reliability functions with commercial functions.
☒ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards

Related Standards	
Standard No.	Explanation
BAL-001-0.1a	Real Power Balancing Control Performance
BAL-002-01	Disturbance control standard
BAL-002-WECC	Regional Contingency Reserve standard
COM-001-1.1	Telecommunications
COM-002-2	Communications and Coordination
PRC-010-0	Planning for Undervoltage Load shedding
PER-005-1	Training

Related SARs	
SAR ID	Explanation
	None

Regional Variances	
Region	Explanation
ERCOT	

Regional Variances	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

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Five-Year Review Template – EOP-001-2.1b

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-001-2.1b Emergency Operations Planning
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111, ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

☒ Yes

☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

☒ Yes

☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

☐ Yes

☒ No

Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

☒ Yes

☐ No

Questions for SME Review Team

If NERC staff answered “Yes” to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:
   Requirement R3:

   - Requirement R3.1 should be covered by EOP-001-2.1b Requirement R4 in Attachment 1 (notifications that should be included in the plan are identified). COM-001 and COM-002 are descriptive in the identification of protocols to use and, thus, adequately cover the generic reference. With the recommended revision to Attachment 1 of EOP-001-2.1b, along with COM-001 and COM-002 generic reference, Requirement R3.1 would meet Criterion B7 as redundant, as well as Criterion A (Requirement R3.1 does little, if anything, to benefit or protect the reliable operation of the BES) of Paragraph 81 and should be retired.
   - Requirement R3.2 should be covered by EOP-001-2.1b Requirement R4 in Attachment 1, which lists the actions to take during capacity situations specified in the plan. Load reduction within timelines is covered in BAL-002 Requirement R2. With the recommended revision of EOP-001 Requirement R4, Requirement R3.2 would meet Criterion B7 as redundant, as well as Criterion A (R3.1 does little, if anything, to benefit or protect the reliable operation of the BES) of Paragraph 81 and should be retired.
   - Requirement R3.4 meets Paragraph 81 Criterion B1; staffing levels are administrative in nature and would result in an increase in efficiency in the ERO compliance program (it is a simple check off during an audit). Requirement R3.4 also meets with Criterion A of Paragraph 81, as a check-off does not enhance the reliability of the BES. Requirement R3.4 should be retired as falling under Criterion B1 and Criterion A of Paragraph 81.

   Requirement 6 in its entirety:

   - Requirement R6.1 is redundant with COM-001, meeting Criterion B7 as redundant under Paragraph 81 and should be retired.
   - Requirement R6.2 speaks to an action to be taken during capacity issues that is not feasible in accomplishing. Transaction arrangements are also a commercial practice and, thus, Requirement R6.2 meets Criterion B6 of Paragraph 81 and should be retired.

- Requirement R6.3 is redundant with EOP-001-2b Requirement R4 and Attachment 1, whereby meeting Criterion B7 as redundant under Paragraph 81 and should be retired.
- Requirement R6.4 does not provide for benefit for reliability of the BES, meeting Criterion A of Paragraph 81 and should be retired.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

   Please summarize your assessment:
   The 2009-03 Emergency Operations Five-Year Review Team (EOP FYRT) recommends that EOP-001-2.b and EOP-002-3.1 be revised and merged into a single standard identifying clearly and separately the Transmission Operator, Generation Operator and Reliability Coordinator issues as they relate to the BA and TOP (to address Paragraph 548 of Order 693) and how it needs to be planned and implemented for on the BES by the specific functional entities.

   - Requirement R1 needs clarity provided as to what an operating agreement constitutes, and adjust the VSL to reflect current interpretations with the number of agreements needed. Requirement R1 must also account for current interpretations found in the Appendix and other interpretations.
   - Requirement R2 needs clarity provided, as instructed by the Commission, on the ambiguity of the EOP standards as they relate to the responsibilities of the Transmission Operator and Balancing Authority.
   - Requirement R5, the need to share emergency plans with neighboring Transmission Operators and Balancing Authorities, should be removed as an administrative burden (identified in P81); however, the remaining language of the requirement should be affirmed.
   - Review is recommended for Attachment 1 as it relates to the GOP in light of recent BES events (Cold Weather Event).

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☒ Yes

☐ No

Please explain:
Appendix 1 attempts to define what a remote Balancing Authority is and should be addressed in future revisions of the Standard

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

   Additional measures must be provided with this standard. There are no performance measures. There are no VRFs with this standard. Requirement R1, once recommended clarity is provided as to what an operating agreement constitutes, adjustment to the VSL will be necessary to reflect current interpretations with the number of agreements needed.

   ☐ Yes

   ☒ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

   ☐ Yes

   ☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☐ Yes

☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE – Requirement R1, R2, R5 and Attachment 1

☒ RETIRE – Requirements R3.1, R3.2, R3.4, R6.1, R6.2, R6.3, R6.4

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE – Requirements R1, R2, R5 and Attachment 1

☒ RETIRE – Requirements R3.1, R3.2, R3.4; Requirement R6 in its entirety; R6.1, R6.2, R6.3, R6.4

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities (“entities”) to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines “reliable operation” as: “… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements.”

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

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[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Five-Year Review Template – EOP-002-3

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-002-3.1 Capacity and Energy Emergencies
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111,ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information *(to be completed by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   - Requirement R1 is redundant with IRO-001 and PER-001-2 and should be retired under Criterion B7 of Paragraph 81.
   - Requirement R6 is redundant with BAL-002-1a and should be retired under Criterion B7 of Paragraph 81.
   - Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR, and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired. Due to the retirement of R9, LSE applicability should be removed in the standard.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

Please summarize your assessment:
The EOP FYRT recommends that EOP-001-2b and EOP-002-3.1 be revised and merged into a single standard to address redundancy in the stating that a plan should be implemented. Both standards are different enough that those requirements not identified in retirement recommendations under Paragraph 81 should be retained.

Requirement R8 and Attachment 1 have several issues regarding applicability to different functions and should be revised to eliminate discrepancies and for clarity. Attachment 1 needs to be reviewed for consistency with IRO and TOP standards. The EOP FYRT recommends review of the uniqueness as it relates to ERCOT and similarly situated BAs. The EOP FYRT recommends the future EOP SDT address the directive in Paragraph 573 of Order 693.

The EOP FYRT further recommends a language change in Requirement R2, replacing "interconnected system" with "Bulk Electric System." Requirements R3 and R4 need to be reviewed by the future EOP SDT to further define the word "emergency" (as Capacity Emergency, Emergency, and Energy Emergency are already NERC defined terms). The EOP FYRT recommends the following sentence in Requirement R5 to be struck: "Such unilateral adjustment may overload transmission facilities."

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes

☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

☒ Yes

☐ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or

consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

☐ Yes

☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised: Requirement R9 (recommended for retirement under Paragraph 81) the TSP now has the ability to change the Transmission priority, which is in turn reflected in the IDC.

   ☒ Yes

   ☐ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE (and merge with EOP-001-2b)

☒ RETIRE – Requirements R1, R6 and R9 in its entirety.

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE (and merge with EOP-001-2b); Requirement R2, replacing “interconnected system” with “Bulk Electric System;” language revision in Requirement R2; Requirements R3 and R4 need to be reviewed by the future EOP SDT to further define the word “emergency” (as Capacity Emergency, Emergency, and Energy Emergency are already NERC defined terms); Requirement R5, strike “Such unilateral adjustment may overload transmission facilities.”

☒ RETIRE – Requirements R1, R6, and R9 in its entirety. Due to the retirement of R9, LSE applicability should be removed in the standard.

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

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The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

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B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Five-Year Review Template – EOP-003-2

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-003-2 Load Shedding Plans
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111, ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   - Requirements R5 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R5 speaks to shedding loads in steps; that same process will be done in Requirement R1. Requirement R5 should be retired under Criterion B7 of Paragraph 81.
   - Requirements R6 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R6 speaks of two events that must be valid to tell the BA or TOP to shed more load, but overall the action of shedding load to meet insufficient generation is the same as stated in Requirement R1. Requirement R6 should be retired under Criterion B7 of Paragraph 81.
   - EOP-003-2– Recommend that Requirements R2, R4 and R7 be moved to PRC-010-0 or otherwise addressed during Project 2008-02 – Undervoltage Load Shedding.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

Please summarize your assessment:
The EOP FYRT team believes that Requirements R2, R4 and R7 should be coordinated with the revision of PRC-010 (Project 2008-02 Undervoltage Load Shedding) for inclusion in that standard. This is consistent with the review that was done for automatic underfrequency requirements and should also be performed for automatic undervoltage requirements.

Based on the recommendations received during the comment period, EOP FYRT further recommends R1 and R8 be considered to be combined. The EOP FYRT also received comments that EOP-003-2 should be combined with EOP-001-2.1b and EOP-002-3.1, and the EOP FYRT recommends this be evaluated in the SAR. In addition, the EOP FYRT recommends that the future EOP SDT evaluate the separation of the functional entity capabilities of the BA and the TOP responsibilities.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes

☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

The Measures and Data retention should be reviewed and updated

☐ Yes

☒ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

☐ Yes

☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☐ Yes

   ☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE – Retire Requirements R5, R6, R2, R4 and R7 and address directives in Paragraphs 595 and 603 of Order 693

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*: See responses to questions 1, 2, and 4 above.

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE - Retire Requirements R5, R6, R2, R4 and R7 and address directives in Paragraphs 595 and 603 or Order 693; recommend for consideration Requirements R1 and R8 be combined; consider combining EOP-003-2 with EOP-001-2.1b and EOP-002-3.1; evaluate the separation of the functional entity capabilities of the BA and TOP responsibilities.

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Project 2009-03 Emergency Operations

EOP-011-1 – Emergency Operations Informal Comment Period Unofficial Comment Form

Instructions

Please **DO NOT** use this form for commenting. Please use the electronic comment form to submit comments on the proposed EOP-011-1. Comments must be submitted by 8 p.m. **April 28, 2014**. If you have questions please contact Laura Anderson or by telephone at 404-446-9671.

Background Information

EOP-011-1 is a new standard that consolidates requirements from three existing Emergency Operations standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

The Project 2009-03 Emergency Operations Standard Drafting Team (EOP SDT) developed EOP-011-1 by considering the following inputs:

- Applicable FERC directives;
- EOP Five Year Review Team (FYRT) recommendations;
- Independent Expert Review Panel recommendations; and
- Paragraph 81 criteria.

The purpose of EOP-011-1 is to mitigate the effects of operating Emergencies, up to and including manual Load shedding, by implementing Emergency Operating Plans. The standard streamlines the requirements for Emergency Operations for the BES into a clearer and more concise standard that is organized by Functional Entity in order to eliminate the ambiguity in previous versions. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

All *Elements for Consideration in Development of Emergency Plans* from Attachment 1 of EOP-001-2.1b were considered by the EOP SDT and incorporated into the requirements of proposed EOP-011-1.

Questions

1. Based on the EOP FYRT recommendations, the EOP SDT has combined three standards into the proposed EOP-011-1, Emergency Operations. The original standards are EOP-001-2.1b (Emergency Operations Planning), EOP-002-3.1 (Capacity and Energy Emergencies) and EOP-003-2 (Load Shedding Plans). Do you support the consolidation of these standards? If not, please provide specific recommendations for the EOP SDT in your comments.

   ☐ Yes
   ☐ No

   Comments:

2. The EOP SDT has developed proposed Requirement R1 to specify the minimum set of elements required for the Transmission Operator to include in their Emergency Operating Plan. Do you agree with the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language.

   ☐ Yes
   ☐ No

   Comments:

3. The EOP SDT has developed proposed Requirement R1, Part 1.2.5 as a process to include manual Load shedding plan coordination. Do you agree that Requirement 1, Part 1.2.5 clearly defines required performance? If not, please provide specific suggestions for improvement, including alternate language.

   ☐ Yes
   ☐ No

   Comments:

4. The EOP SDT has developed proposed EOP-011-1, Requirement R1, Part 1.2.5 without a specific time measure. The currently-enforceable EOP-003-2, Requirement R8 states, "… timeframe adequate for

responding to the emergency.” Do you support Requirement R1, Part 1.2.5 without a time measure? If not, please provide specific suggestions for improvement, including alternate language.

☐ Yes
☐ No

Comments:

5. The EOP SDT developed Requirement R2 to specify the minimum set of elements required for the Balancing Authority to include in their Emergency Operating Plan. Do you agree with the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language.

☐ Yes
☐ No

Comments:

6. The EOP SDT has developed proposed Requirement R2, Part 2.2.8 as a process to include manual Load shedding plan coordination. Do you agree that Requirement R2, Part 2.2.8 clearly defines required performance? If not, please provide specific suggestions for improvement, including alternate language.

☐ Yes
☐ No

Comments:

7. The EOP SDT has developed proposed Requirement R2, Part 2.2.8 without time measure. The currently-enforce EOP-003-2, Requirement R8 states, “… timeframe adequate for responding to the emergency.” Do you support Requirement R2, Part 2.2.8 without a time measure? If not, please provide specific suggestions for improvement, including alternate language.

☐ Yes
☐ No

Comments:

8. The EOP SDT has developed a requirement to address a directive from Paragraph 548 of FERC Order No. 693. This directive states “…the Commission finds the reliability coordinator is a necessary entity

under EOP-001-0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity.” Requirement R3 requires the Reliability Coordinator to coordinate the Emergency Operating Plans of the entities in its Reliability Coordinator Area to provide a wide-area perspective and to ensure that they are compatible and support reliability in the Reliability Coordinator Area. This also relates to Requirement R3, Part 3.3 of EOP-001-2.1b, which requires coordination of plans. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language.

☐ Yes
☐ No

Comments:

9. In addition to Requirement R3, the EOP SDT proposes an additional requirement, Requirement R4, applicable to the Reliability Coordinator to address the Order No. 693, Paragraph 548 directive. The proposed Requirement R4 requires the Reliability Coordinator to approve or disapprove Transmission Operator and Balancing Authority Emergency Operating Plans within 30 days of submittal. Since these Emergency Operating Plans are submitted on an agreed-upon schedule, the EOP SDT believes that 30 days is adequate time for the Reliability Coordinator to assess the plans. Do you support the proposed changes? If not, please provide specific suggestions for improvement, including alternate language.

   ☐ Yes
   ☐ No

   Comments:

10. The EOP SDT has developed proposed Requirement R5 to have a Transmission Operator that is experiencing an operating Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. This is a corollary requirement to existing EOP-002-3.1, Requirement R3; whereby the Balancing Authority performs a similar notification for its Emergencies. Do you support the proposed Requirement R5? If not, please provide specific suggestions for improvement, including alternate language.

    ☐ Yes
    ☐ No

    Comments:

11. The EOP SDT has developed proposed Requirement R6 to have a Balancing Authority that is experiencing a capacity or Energy Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. This is a revision to existing EOP-002-3.1, Requirement

R3. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language.

☐ Yes
☐ No

Comments:

12. The EOP SDT has developed proposed Requirement R7 to have a Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator to notify, as soon as practicable, impacted Reliability Coordinators, Balancing Authorities and Transmission Operators. This is a revision to existing EOP-002-3.1, Requirement R3. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language.

☐ Yes
☐ No

Comments:

13. The EOP SDT has revised EOP-002-3.1, Requirement R6, Part 6.5 and Requirement R7, Part 7.2 and included it in EOP-011-1 as Requirement R8. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language.

☐ Yes
☐ No

Comments:

14. The EOP SDT has revised EOP-002-3.1, Requirement R8 and included it in EOP-011-1 as Requirement R9. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language.

☐ Yes
☐ No

Comments:

15. The EOP SDT has revised Attachment 1 of EOP-002-3.1. Do you support the proposed revisions to Attachment 1? If not, please provide specific suggestions for improvement.

☐ Yes
☐ No

Comments:

16. The EOP SDT has considered technical justification to remove Attachment 1 from the proposed EOP-011-1. If Attachment 1 were to be removed, the SDT proposes that NERC's Energy Emergency Alert levels be incorporated into the NERC Glossary as defined terms, with some of the additional information in Attachment 1 incorporated as a guidance document. Would you support this approach? If not, please provide specific suggestions for an alternate approach that you would support.

☐ Yes
☐ No

Comments:

17. Do you have any other comments regarding proposed EOP-011-1, not included above, that you would like to provide to the EOP SDT? If so, please provide specific comments for improvement.

☐ Yes
☐ No

Comments:

Proposed Definitions for the NERC Glossary of Terms

Project 2009-03: Emergency Operations

The Emergency Operations Standards Drafting (EOP SDT) proposes revisions to a defined term in the NERC Glossary of Terms. This defined term is used in the EOP family of standards and in other standards or defined terms as discussed below.

Proposed revised definitions (redlined):

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide its ~~customers'~~ expected ~~energy~~ Load requirements.

This defined term was revised to provide clarity that an energy emergency is not necessarily limited to a Load-Serving Entity.

This defined term, or variations of it, is also used in the instances below.~~–~~ The EOP SDT does not believe that the proposed revisions change the reliability intent of these standard or definitions.

BAL-002-WECC – Contingency Reserve

R1.~~–~~ Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is: [Violation Risk Factor: High] [Time Horizon: Real-time operations]

1.1 The greater of either:
- The amount of Contingency Reserve equal to the loss of the most severe single contingency;
- The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.

1.2 Comprised of any combination of the reserve types specified below:
- Operating Reserve – Spinning
- Operating Reserve - Supplemental
- Interchange Transactions designated by the Source Balancing Authority as Operating Reserve – Supplemental
- Reserve held by other entities by agreement that is deliverable on Firm Transmission Service

- A resource, other than generation or load, that can provide energy or reduce energy consumption
- Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.
- All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.

1.3 Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).

1.4 An amount of capacity from a resource that is deployable within ten minutes.

The term is also used in the following standards that are proposed to be retired when EOP-011-1 becomes enforceable.

EOP-001-2.1b — Emergency Operations Planning; Attachment 2, Interpretation, Responses, Item 2

2.– The intent is that all Balancing Authorities, interconnected by AC ties or DC (asynchronous) ties within the same Interconnection, have emergency energy assistance agreements with at least one Adjacent Balancing Authority and have sufficient emergency energy assistance agreements to mitigate reasonably anticipated energy emergencies. However, the standard does not require emergency energy assistance agreements with all Adjacent Balancing Authorities, nor does it preclude having an emergency assistance agreement across Interconnections.

EOP-002-3.1 — Capacity and Energy Emergencies

R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.

R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan to reduce risks to the interconnected system.

R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.

R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.

R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to:

R6.1. Loading all available generating capacity.
R6.2. Deploying all available operating reserve.
R6.3. Interrupting interruptible load and exports.
R6.4. Requesting emergency assistance from other Balancing Authorities.
R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and
R6.6. Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.

R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall:

R7.1. Manually shed firm load without delay to return its ACE to zero; and
R7.2. Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 “Energy Emergency Alerts.”

R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 “Energy Emergency Alerts.” The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.

R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff:

R9.1. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 “Energy Emergency Alerts.”
R9.2. The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed.

R9.3. The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.
R9.4. The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.

IRO-005-3.1a — Reliability Coordination — Current Day Operations

Note:~~–~~ This standard was revised under Project 2006-06 and the reference below was removed from the standard.~~–~~ The standard was approved by the NERC BOT and filed with FERC. NERC ~~subsequently withdrew its petition~~has requested the FERC defer action on its petition and is revising this standard under project 2014-03, TOP / IRO Revisions.~~–~~ This project is scheduled to be completed no later than January 31, 2015.

R2. Each Reliability Coordinator shall monitor its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the Reliability Coordinator shall direct the Balancing Authorities in the Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The Reliability Coordinator shall issue Energy Emergency Alerts as needed and at the request of its Balancing Authorities and Load-Serving Entities.

MOD-004-1 — Capacity Benefit Margin:~~–~~ This standard is being retired and replaced with MOD-001-2 — Modeling, Data, and Analysis — Available Transmission System Capability (NERC BOT approved February 6, 2014).~~–~~ The term "energy emergency" is not used in the new standard.

R10. The Load-Serving Entity or Balancing Authority shall request to import energy over firm Transfer Capability set aside as CBM only when experiencing a declared NERC Energy Emergency Alert (EEA) 2 or higher. [Violation Risk Factor: Lower] [Time Horizon: Same-day Operations]

Defined term Emergency Request for Interchange:~~–~~ This term is not used in any existing approved standard.

Emergency Request for Interchange: Request for Interchange to be initiated for Emergency or Energy Emergency conditions.

Project 2009-03 - Emergency Operations

Mapping Document

Project Purpose

The Emergency Operations Five-Year Review Team (EOP FYRT) was appointed by the Standards Committee Executive Committee on April 22, 2013. The EOP FYRT has reviewed the following Emergency Operations standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 to decide if revisions are needed in the scope of this project in relation to P81 and FERC directives. This project is a comprehensive review of this set of EOP standards to ensure that the requirements are clear and unambiguous. Many of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process, and the standards were due for a comprehensive review. Suggestions for improvement, possible consolidation and for requirements to be considered for retirement under Paragraph 81 have been submitted by stakeholders, other drafting teams and FERC staff.

On October 17, 2013 the Standards Committee accepted the recommendations of the EOP FYRT and appointed a drafting team to implement the recommendations and begin formal development. The Standards Committee further authorized the posting of the Standard Authorization Request (SAR) developed by the EOP FYRT.

Project 2009-03 – Emergency Operations (EOP-011-1) is being coordinated with Project 2008-02 – Undervoltage Load Shedding, which proposes to retire EOP-003-2 Requirements R2, R4, and R7 since these requirements are proposed to be covered by PRC-010-1, Requirement R1; this translation is illustrated in this document and will also be referenced in Project 2008-02's mapping document. The project schedules and implementation plans for these two projects are being closely coordinated to ensure that no gaps or duplication will result from the products developed by the two drafting teams.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.	Translated to EOP-011-1, Emergency Operations; retired provisions regarding assistance from remote Balancing Authorities.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 2.2.1. Generating resources in its Balancing Authority Area: 2.2.1.1. capability and availability; 2.2.1.2. fuel supply and inventory concerns; 2.2.1.3. fuel switching capabilities; 2.2.1.4. environmental constraints. 2.2.2 Voluntary Load reductions; 2.2.3. Public appeals; 2.2.4. Governmental programs;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.5. Reduction of internal utility energy use; 2.2.6. Customer fuel switching; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 2.2.9. Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan. 2.3 A process for revising its Emergency Operating Plan to account for changes in its System.
R2. Each Transmission Operator and Balancing Authority shall: **R2.1.** Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity. **R2.2.** Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system.	Translated to EOP-011-1, Emergency Operations	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R2.3. Develop, maintain, and implement a set of plans for load shedding		1.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 1.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 1.2.1. Plans to control voltage; 1.2.2. Processes for cancelling or recalling Transmission outages; 1.2.3 Processes for System reconfiguration; 1.2.4. Processes for redispatch of generation; 1.2.5. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 1.2.6. Strategies to be used to mitigate reliability impacts of extreme weather conditions. 1.3. A process for revising its Emergency Operating Plan to account for changes in its System. **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: *[Violation*

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 2.2.1. Generating resources in its Balancing Authority Area: 2.2.1.1. capability and availability; 2.2.1.2. fuel supply and inventory concerns; 2.2.1.3. fuel switching capabilities; 2.2.1.4. environmental constraints. 2.2.2 Voluntary Load reductions; 2.2.3. Public appeals; 2.2.4. Governmental programs; 2.2.5. Reduction of internal utility energy use; 2.2.6. Customer fuel switching; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.9 Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan. 2.3 A process for revising its Emergency Operating Plan to account for changes in its System.
R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include: **R3.1.** Communications protocols to be used during emergencies. **R3.2.** A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions. **R3.3.** The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities. **R3.4.** Staffing levels for the emergency.	Translated to EOP-011-1, Emergency Operations; Retired R3.1 under Criteria A and B7 of Paragraph 81 guidelines; Retired R3.4 under Criteria A and B1 of Paragraph 81 guidelines	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include: [*Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* 1.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 1.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 1.2.1. Plans to control voltage; 1.2.2. Processes for cancelling or recalling Transmission outages; 1.2.3. Processes for System reconfiguration;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.4. Processes for redispatch of generation; 1.2.5. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 1.2.6. Strategies to be used to mitigate reliability impacts of extreme weather conditions. 1.3. A process for revising its Emergency Operating Plan to account for changes in its System. **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: [*Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning*] 2.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 2.2.1. Generating resources in its Balancing Authority Area:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1.1. capability and availability; 2.2.1.2. fuel supply and inventory concerns; 2.2.1.3. fuel switching capabilities; 2.2.1.4. environmental constraints. 2.2.2. Voluntary Load reductions; 2.2.3. Public appeals; 2.2.4. Governmental programs; 2.2.5. Reduction of internal utility energy use; 2.2.6. Customer fuel switching; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 2.2.9. Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan. 2.3. A process for revising its Emergency Operating Plan to account for changes in its System. **Old R3.3 maps to new R3** R3. Each Reliability Coordinator shall coordinate the Emergency Operating Plans of the entities in its

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Reliability Coordinator Area to ensure that the plans are compatible and support reliability in the Reliability Coordinator Area. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*
R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan.	Translated to EOP-011-1, Emergency Operations	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* 1.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 1.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 1.2.1. Plans to control voltage; 1.2.2. Processes for cancelling or recalling Transmission outages; 1.2.3 Processes for System reconfiguration;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.4. Processes for redispatch of generation; 1.2.5. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 1.2.6. Strategies to be used to mitigate reliability impacts of extreme weather conditions. 1.3 A process for revising its Emergency Operating Plan to account for changes in its System. **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* 2.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 2.2.1. Generating resources in its Balancing Authority Area:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1.1. capability and availability; 2.2.1.2. fuel supply and inventory concerns; 2.2.1.3. fuel switching capabilities; 2.2.1.4. environmental constraints. 2.2.2 Voluntary Load reductions; 2.2.3. Public appeals; 2.2.4. Governmental programs; 2.2.5. Reduction of internal utility energy use; 2.2.6. Customer fuel switching; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 2.2.9. Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan. 2.3 A process for revising its Emergency Operating Plan to account for changes in its System.
R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority	Translated to EOP-011-1, Emergency Operations	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.		Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* 1.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 1.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 1.2.1. Plans to control voltage; 1.2.2. Processes for cancelling or recalling Transmission outages; 1.2.3 Processes for System reconfiguration; 1.2.4. Processes for redispatch of generation; 1.2.5. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 1.2.6. Strategies to be used to mitigate reliability impacts of extreme weather conditions. 1.3 A process for revising its Emergency Operating Plan to account for changes in its System. **EOP-011-1, R2**

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* 2.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 2.2.1. Generating resources in its Balancing Authority Area: 2.2.1.1. capability and availability; 2.2.1.2. fuel supply and inventory concerns; 2.2.1.3. fuel switching capabilities; 2.2.1.4. environmental constraints. 2.2.2 Voluntary Load reductions; 2.2.3. Public appeals; 2.2.4. Governmental programs; 2.2.5. Reduction of internal utility energy use; 2.2.6. Customer fuel switching;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 2.2.9. Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan. 2.3 A process for revising its Emergency Operating Plan to account for changes in its System.
R6. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable: **R6.1.** The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems. **R6.2.** The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency	Retired under Paragraph 81 guidelines	**Retired per P81 (redundant); however the reliability concept is addressed in R3, requiring the Reliability Coordinator to coordinate the Emergency Operation Plans of the entities in its Reliability Coordinator Area.** **EOP-011-1, R3** R3. Each Reliability Coordinator shall coordinate the Emergency Operating Plans of the entities in its Reliability Coordinator Area to ensure that the plans are compatible and support reliability in the Reliability Coordinator Area. [*Violation Risk Factor: Medium*] [*Time Horizon: Operations Planning*]

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
capacity or energy transfers if existing agreements cannot be used. **R6.3.** The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.) **R6.4.** The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.		

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.	Retired under Criteria A and B7 of P81 guidelines	**Retired – redundant with PER-001, R1 with respect to the Balancing Authority and IRO-001-1.1, Requirement R3 for the Reliability Coordinator.**
R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan to reduce risks to the interconnected system.	Translated to EOP-011-1, Emergency Operations	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 6.2.1. Generating resources in its Balancing Authority Area:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1.1. capability and availability; 2.2.1.2. fuel supply and inventory concerns; 2.2.1.3. fuel switching capabilities; 2.2.1.4. environmental constraints. 2.2.2 Voluntary Load reductions; 2.2.3. Public appeals; 2.2.4. Governmental programs; 2.2.5. Reduction of internal utility energy use; 2.2.6. Customer fuel switching; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 2.2.9. Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan. 2.3 A process for revising its Emergency Operating Plan to account for changes in its System.
R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions	Translated to EOP-011-1, Emergency Operations	**EOP-011-1, R5** R5. Each Transmission Operator that is experiencing an operating Emergency on its Transmission System shall

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
to its Reliability Coordinator and neighboring Balancing Authorities.		communicate the Emergency and its current and projected System conditions to its Reliability Coordinator. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations] **EOP-011-1, R6** R6. Each Balancing Authority that is experiencing a capacity or Energy Emergency shall communicate the Emergency and its current and projected System conditions to its Reliability Coordinator. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations] **EOP-011-1, R7** R7. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as practicable, impacted Reliability Coordinators, Balancing Authorities and Transmission Operators. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions		**EOP-011-1, R2**

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.	Translated to EOP-011-1, Emergency Operations	R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 6.2.1. Generating resources in its Balancing Authority Area: 2.2.1.1. capability and availability; 2.2.1.2. fuel supply and inventory concerns; 2.2.1.3. fuel switching capabilities; 2.2.1.4. environmental constraints. 2.2.2 Voluntary Load reductions; 2.2.3. Public appeals; 2.2.4. Governmental programs; 2.2.5. Reduction of internal utility energy use; 2.2.6. Customer fuel switching;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 2.2.9. Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan. 2.3 A process for revising its Emergency Operating Plan to account for changes in its System. **EOP-011-1, R8** R8. The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert after the Balancing Authority has performed the steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency		**EOP-011-1, R2**

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.	Translated to EOP-011-1, Emergency Operations	R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 6.2.1. Generating resources in its Balancing Authority Area: 2.2.1.1. capability and availability; 2.2.1.2. fuel supply and inventory concerns; 2.2.1.3. fuel switching capabilities; 2.2.1.4. environmental constraints. 2.2.2 Voluntary Load reductions; 2.2.3. Public appeals; 2.2.4. Governmental programs; 2.2.5. Reduction of internal utility energy use; 2.2.6. Customer fuel switching;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 2.2.9. Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan. 2.3 A process for revising its Emergency Operating Plan to account for changes in its System.
R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 “Energy Emergency Alerts.” The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.	Translated to EOP-011-1, Emergency Operations	**EOP-011-1, R9** R9. Each Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate a NERC Energy Emergency Alert, as detailed in Attachment 1. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network	Retired per P81 – this is addressed in	**LSEs have no Real-time reliability functionality with respect to EEAs.**

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration transmission Service from designated Network Resources) as permitted in its transmission tariff: **R9.1**. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts." **R9.2.** The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed. **R9.3.** The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7. **R9.4.** The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange	NAESB tagging specification.	Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Transaction on the system from Priority 6 to Priority 7.		

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.	Translated to EOP-011-1, Emergency Operations	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 1.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 1.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 1.2.1. Plans to control voltage;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.2. Processes for cancelling or recalling Transmission outages; 1.2.3 Processes for System reconfiguration; 1.2.4. Processes for redispatch of generation; 1.2.5. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 1.2.6. Strategies to be used to mitigate reliability impacts of extreme weather conditions. 1.3 A process for revising its Emergency Operating Plan to account for changes in its System. **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 6.2.1. Generating resources in its Balancing Authority Area: 2.2.1.1. capability and availability; 2.2.1.2. fuel supply and inventory concerns; 2.2.1.3. fuel switching capabilities; 2.2.1.4. environmental constraints. 2.2.2 Voluntary Load reductions; 2.2.3. Public appeals; 2.2.4. Governmental programs; 2.2.5. Reduction of internal utility energy use; 2.2.6. Customer fuel switching; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 2.2.9. Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan. 2.3 A process for revising its Emergency Operating Plan to account for changes in its System.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.	EOP-003-2, R2 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall demonstrate its effectiveness prior to implementing the program. This demonstration shall include, but is not limited to, studies and analyses that show: **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to the UVLS Program's design. **1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, auto-reclosing, SPSs, and other UVLS programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to real-time operations and the operations planning time horizon.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.	Translated to EOP-011-1, Emergency Operations	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 1.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 1.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 1.2.1. Plans to control voltage; 1.2.2. Processes for cancelling or recalling Transmission outages; 1.2.3 Processes for System reconfiguration; 1.2.4. Processes for redispatch of generation; 1.2.5. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 1.2.6. Strategies to be used to mitigate reliability impacts of extreme weather conditions.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.3 A process for revising its Emergency Operating Plan to account for changes in its System. **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 6.2.1. Generating resources in its Balancing Authority Area: 2.2.1.1. capability and availability; 2.2.1.2. fuel supply and inventory concerns; 2.2.1.3. fuel switching capabilities; 2.2.1.4. environmental constraints. 2.2.2 Voluntary Load reductions;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3. Public appeals; 2.2.4. Governmental programs; 2.2.5. Reduction of internal utility energy use; 2.2.6. Customer fuel switching; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 2.2.9. Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan. 2.3 A process for revising its Emergency Operating Plan to account for changes in its System. **EOP-011-1, R3** R3. Each Reliability Coordinator shall coordinate the Emergency Operating Plans of the entities in its Reliability Coordinator Area to ensure that the plans are compatible and support reliability in the Reliability Coordinator Area. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning]

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels.	EOP-003-2, R4 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design. EOP-003-2, R4 is inherently embedded in PRC-010-1, R1, Part 1.1. The specific items noted are described in PRC-010-1's Guidelines and Technical Basis.	**Proposed Language in PRC-010-1** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall demonstrate its effectiveness prior to implementing the program. This demonstration shall include, but is not limited to, studies and analyses that show: **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to the UVLS Program's design. **1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, auto-reclosing, SPSs, and other UVLS programs. **These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.**

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.	Retired under Criteria A and B7 of Paragraph 81.	**Redundant with R1 of EOP-003-2, which maps to EOP-011-1, R1 and R8.** Requirement R5 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R5 speaks to shedding Loads in steps; that same process will be done in Requirement R1. Requirement R5 should be retired under Criterion B7 of Paragraph 81. Automatic underfrequency Load shedding is addressed in PRC-006, while undervoltage Load shedding is addressed in PRC-010.
R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency	Retired under Criteria and B7 of Paragraph 81.	**Redundant with R1 of EOP-003-2, which maps to EOP-011-1, R1 and R8.** Requirement R6 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
load shedding, the Transmission Operator or Balancing Authority shall shed additional load.		requirement. Requirement R6 speaks of two events that must be valid to tell the BA or TOP to shed more Load, but overall the action of shedding Load to meet insufficient generation is the same as stated in Requirement R1. Requirement R6 should be retired under Criterion B7 of Paragraph 81. Automatic underfrequency Load shedding is addressed in PRC-006 while undervoltage Load shedding is addressed in PRC-010.
R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions.	EOP-003-2, R7 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design.	Proposed Language in PRC-010-1: **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall demonstrate its effectiveness prior to implementing the program. This demonstration shall include, but is not limited to, studies and analyses that show: **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to the UVLS Program's design.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
	EOP-003-2, R7 is inherently embedded in PRC-010-1, R1, Part 1.2. The specific items noted are described in PRC-010-1's Guidelines and Technical Basis.	**1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, auto-reclosing, SPSs, and other UVLS programs. **These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.**
R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.	Translated to EOP-011-1, Emergency Operations	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 1.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 1.2.1. Plans to control voltage; 1.2.2. Processes for cancelling or recalling Transmission outages; 1.2.3 Processes for System reconfiguration; 1.2.4. Processes for redispatch of generation; 1.2.5. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 1.2.6. Strategies to be used to mitigate reliability impacts of extreme weather conditions. 1.3 A process for revising its Emergency Operating Plan to account for changes in its System. **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: [Violation Risk Factor: High]

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		[Time Horizon: Real-Time Operations, Operations Planning] 2.1. Definition of roles and responsibilities to activate and implement the Emergency Operating Plan. 2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 6.2.1. Generating resources in its Balancing Authority Area: 2.2.1.1. capability and availability; 2.2.1.2. fuel supply and inventory concerns; 2.2.1.3. fuel switching capabilities; 2.2.1.4. environmental constraints. 2.2.2 Voluntary Load reductions; 2.2.3. Public appeals; 2.2.4. Governmental programs; 2.2.5. Reduction of internal utility energy use; 2.2.6. Customer fuel switching; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.9. Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan. 2.3 A process for revising its Emergency Operating Plan to account for changes in its System.

Project 2009-03 Emergency Operations and Planning

Background and Rationale for revisions of EOP-001-2.1b, EOP-002-3.1 and EOP-003-2

Overview

EOP-011-1 is a new standard that consolidates requirements from three existing Emergency Operations standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

The Project 2009-03 Emergency Operations Standard Drafting Team (EOP SDT) developed EOP-011-1 by considering the following inputs:

- Applicable FERC directives;
- Five Year Review Team (FYRT) recommendations;
- Independent Expert Review Panel recommendations; and
- Paragraph 81 criteria.

The purpose of EOP-011-1 is to mitigate the effects of operating Emergencies, up to and including manual Load shedding, by implementing Emergency Operating Plans. The standard streamlines the requirements for Emergency Operations for the BES into a clearer and more concise standard that is organized by Functional Entity in order to eliminate the ambiguity in previous versions. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

All *Elements for Consideration in Development of Emergency Plans* from Attachment 1 of EOP-001-2.1b were considered by the EOP SDT and incorporated into the requirements of proposed EOP-011-1.

History and Inputs to Project 2009-03 Emergency Operations

Periodic Review of EOP Standards

The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every 10 years, or once every five years for any Reliability Standard approved by the American National Standards Institute as an American National Standard.[1] The Emergency Operations Five-Year Review Team (EOP FYRT) was appointed by the Standards Committee Executive Committee on April 22, 2013. The EOP FYRT reviewed the following Emergency Operations standards: EOP-001-2.1b (Emergency Operations Planning), EOP-002-3.1 (Capacity and Energy Emergencies) and EOP-003-2 (Load Shedding Plans) to determine if the standards should be retained, retired or if revisions were needed in the scope of this project in relation to P81 criteria, Independent Expert report and FERC directives.

[1] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf

The scope of the review included consideration of recommendions from the Industry Expert Review Panel report, Paragraph 81 recommendations and criteria, and outstanding FERC Order No. 693 directives, as well as industry comments. The EOP FYRT posted its draft recommendations to revise the standards for stakeholder comment. After reviewing stakeholder comments, the EOP FYRT submitted its final recommendations to the Standards Committee, along with a Standard Authorization Request (SAR). This SAR replaces an earlier SAR, and the new SAR provided the scope for the work of Project 2009-03. The EOP SDT implemented the FYRT recommendations into proposed reliability standard EOP-011-1.

Industry Expert Report[2]

In 2013 NERC assembled a panel of Industry Experts (the IERP) to review all reliability standards and provide recommendations for consideration in the transition of NERC standards to steady state. For the Emergency Operations and Planning reliability standards, the Industry Experts made the following recommendations:

- EOP-001-2.1b, R6 - P81. Duplicative of R4 and the Attachment
- EOP-002-3.1, R2 - P81. Duplicative - requirement to take action is in R1.
- EOP-002-3.1, R3 - P81. Duplicative of what is required to be in the plan under Attachment 1 of EOP-001.
- EOP-002-3.1, R6 -P81. Duplicative of BAL standards to meet CPS and DCS
- EOP-002-3.1, R9 - P81. This is a market (tariff) issue.
- EOP-003-2, R2 - P81. Duplicative of PRC-010 and TPL standards
- EOP-003-2, R4 - P81. Duplicative of PRC-010 and TPL standards
- EOP-003-2, R5 - P81. Duplicative of R1 and also covered under standards for TOP (TOP-002-3)
- EOP-003-2, R6 - P81. Duplicative; an entity does the same actions as when not islanded.
- EOP-003-2, R7 - P81. Duplicative of PRC-010 R1

As part of the EOP Five-Year Review process, the EOP FYRT evaluated these recommendations and generally agrees with them, with exceptions and further considerations for the standard drafting team, as noted below:

- EOP-001-2.1b - the EOP FYRT concurred with the recommendation to retire R6 in accordance with the applicable Paragraph 81 criteria (Requirements 6.1 and 6.3 under Criterion B7; Requirement R6.2 under Criterion B6; and Requirement R6.4 under Criterion A). In addition, the EOP FYRT also recommended that the future EOP SDT take into consideration retiring Requirements R3.1 under Criterion B7, Requirement R3.2 under Criterion B7 and Criterion A, and Requirement R3.4 under Criterion B1 of Paragraph 81.

[2] NERC Standards Independent Expert Review Project, An Independent Review by Industry Experts, posted at http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf

The EOP FYRT further recommended revising and merging EOP-001-2.b and EOP-002-3.1 into a single standard; revising Requirements R1, R2 and R5 and reviewing Attachment 1.

- EOP-002-3.1 - in addition to Requirements R6 and R9, the EOP FYRT recommended retiring Requirements R1 under Criterion B7 of Paragraph 81. The EOP FYRT further recommended that the future EOP SDT consider revising and merging EOP-001-2.b and EOP-002-3.1 into a single standard, which would include a revision to Requirement R3 and Attachment 1.
- EOP-003-2 - the EOP FYRT recommended Requirements R2, R4 and R7 be moved to PRC-010-0 and revised in accordance with the other requirements in that standard. In addition to merging EOP-001-2.1b with EOP-002-3.1, the EOP FYRT recommended the future EOP SDT consider merging EOP-003-2, EOP-001-1-2.1b and EOP-002-3.1 into a single standard.

The EOP FYRT made a strong recommendation for the EOP SDT to consider merging and revising EOP-001-2.b and EOP-002-3.1 into a single standard; not only to streamline and clarify the requirements after applying the Paragraph 81 criteria, but also to invoke the continuous improvement cycle of the reliability standards towards results-based standards (RBS).

Paragraph 81[3]

For a reliability standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy both: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B (identifying criteria). In addition, for each reliability standard requirement proposed for retirement or modification, the data and reference points of Criterion C should be considered for making a more informed decision.

Paragraph 81 recommendations from the Independent Experts and Industry were reviewed and the EOP SDT incorporated those into the development of EOP-011-1.

FERC Directives

In the development of the proposed EOP-011-1 reliability standard, the EOP SDT addressed the outstanding FERC directives in Order No. 693 related to Emergency Operations and planning4. Briefly, the directives applicable to each standard are listed below:

EOP-001-1 Emergency Operations Planning:

- Include reliability coordinators as an applicable entity.
- Consider Southern California Edison's and Xcel's suggestions in the standard development process.
- Clarify that the 30-minute requirement in requirement R2 to state that Load shedding should be capable of being implemented as soon as possible but no more than 30 minutes.
- Includes definitions of system states (e.g. normal, alert, emergency), criteria for entering

[3] NERC – Paragraph 81 Criteria posted at http://www.nerc.com/pa/stand/project%20200812%20coordinate%20interchange%20standards%20dl/paragraph_81_criteria.pdf

[4] Outstanding FERC Order 693 directives listing related to Emergency Operations posted at Project 2009-03 Directives.xlsx

into these states. And the authority that will declare them.

- Consider a pilot program (field test) for the system states proposal.
- Clarifies that the actual emergency plan elements, and not the "for consideration" elements of Attachment 1, should be the basis for compliance.

EOP-002-2 Capacity and Energy Emergencies:

- Address emergencies resulting not only from insufficient generation but also insufficient
- Transmission capability, particularly as it affects the implement of the capacity and energy
- Emergency plan.
- Include all technically feasible resource options, including demand response and generation resources.
- Ensure the TLR procedure is not used to mitigate actual IROL violations.

EOP-003-1 Load Shedding Plans:

- Develop specific minimum Load shedding capability that should be provided and the maximum amount of delay before Load shedding can be implemented based on overarching nationwide criteria that take into account system characteristics.
- Require periodic drills of simulated Load shedding.
- Suggest a review of industry best practices in determining nationwide criteria.
- Consider comments from APPA and ISO-NE in the standards development process.

Rationales for Requirements

Proposed reliability standard EOP-011-1 merges EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 into a single standard applicable to the following functional entities:

- Balancing Authority
- Reliability Coordinator
- Transmission Operator

Rationale for R1: The EOP SDT examined the recommendation of the EOP FYRT and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment, 1 and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Transmission Operator to create an Emergency Operating Plan.

Requirement 1.2.1 was added to this standard for the Transmission Operator to address procedures, processes or strategies to prepare for and mitigate Emergencies using voltage control methods, which could include switching of capacitor and reactor banks, generator reactive output and the use of synchronous condensers.

The topic of manual Load shedding is included in Requirement R1 (Transmission Operator Emergency Operating Plan) and Requirement R2 (Balancing Authority Emergency Operating Plan) because this sometimes requires coordination between the Balancing Authority and Transmission Operator.
The EOP SDT added Requirement R1.3, a revision of Requirement R5 in EOP-001-2.1b, to establish a process for the Transmission Operator to revise its Emergency Operating Plan to account for changes in its System.

Rationale for R2: The EOP SDT took the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1. The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Balancing Authority to create its Emergency Operating Plan to address capacity and energy Emergencies.

Manual Load shedding is included in Requirement R1 (Transmission Operator Emergency Operating Plan) and Requirement R2 (Balancing Authority Emergency Operating Plan) because this sometimes requires coordination between the Balancing Authority and Transmission Operator.

The EOP SDT added Requirement R2.3, a revision of Requirement R5 in EOP-001-2.1b, to establish a process for the Balancing Authority to revise its Emergency Operating Plan to account for changes in its System.

Rationale for R3: The EOP SDT agrees that Transmission Operators and Balancing Authorities should submit Emergency Operating plans to the Reliability Coordinator for approval in order for the Reliability Coordinator to ensure all Emergency Operating Plans in its Reliability Coordinator Area are coordinated and compatible. This requirement makes the standard applicable to the Reliability Coordinator; clearly and separately identifying the Transmission Operator, Balancing Authority and Reliability Coordinator issues as they relate to the Balancing Authority and Transmission Operator (to address Paragraph 548 of Order 693) and how it needs to be planned for on the BES by the specific Functional Entities.

"…the Commission finds the reliability coordinator is a necessary entity under EOP-001-0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity."

Rationale for R4: Since Requirements R1 and R2 both require a submittal for approval, Requirement R4 requires approval or disproval. This aligns with similar requirements in EOP-006-2, Requirement 5.1.

Rationale for R5: This was an existing requirement in EOP-002-3.1 for Balancing Authorities. The EOP SDT has added this as an additional requirement for Transmission Operators. The EOP SDT revised communication of "future system conditions" to "projected system conditions." The purpose of this requirement is to apprise the Reliability Coordinator of the Transmission Operator's Real-time operations preparation and planning.

Rationale for R6: This was an existing requirement in EOP-002-3.1 for Balancing Authorities. The EOP SDT revised communication of "future system conditions" to "projected system conditions." This modification is intended to apprise the Reliability Coordinator of the Balancing Authority Real-time operations preparation and planning.

Rationale for R7: The EOP SDT added the words "as soon as practicable" to the requirement to point to the timeliness and to the relevancy of the Emergencies and to alleviate excessive notifications on Balancing Authorities and Transmission Operators. This was an existing requirement in EOP-002-3.1 for Balancing Authorities.

Rationale for R8: The EOP SDT placed this language in this requirement since it was found in Requirements R6.5 and R7.2 of E0P-002-3.1. The EOP SDT agrees that manual Load shedding and other actions are addressed in the Emergency Operating Plan and it is not necessary to explicitly call for Load shedding to return ACE to zero in this standard. ACE requirements for the Balancing Authority are addressed in the BAL-001 and BAL-002 standards.

Rationale for R9: The EOP SDT retained Requirement R8 from E0P-002-3.1. The Load-Serving Entity has the right, under Attachment 1, to request that an Energy Emergency Alert (EEA) be issued, but it does not have any requirements to do so; therefore, the EOP SDT elected to retain the Load-Serving Entity in the requirement, but not as an applicable entity. If it becomes a reliability issue, the Balancing Authority or Reliability Coordinator will call for the EEA.

Standards Announcement

Project 2009-03 Emergency Operations EOP-011-1

Informal Comment Period Now Open through April 28, 2014

Now Available

A 30-day informal comment period for the draft standard **EOP-011-1 – Emergency Operations** (intended to consolidate and replace EOP-001-2.1b, EOP-002-3.1, and EOP-003-2) is open through **8 p.m. Eastern on Monday, April 28, 2014.**

If you have questions please contact Laura Anderson via email or by telephone at (404) 446-9671.

Background information for this project can be found on the project page.

Project 2008-02 Undervoltage Load Shedding (proposed PRC-010-1) is also currently posted for a 30-day informal comment period. Requirements R2, R4, and R7 in EOP-003-2 – Load Shedding Plans is captured in the proposed PRC-010-1. Stakeholders may wish to review both projects with respect to the transition of these requirements. Both projects and their implementation plans are being closely coordinated to ensure that there is no gap or duplication of requirements created by the work of the two teams.

Instructions for Commenting

Please use the electronic form to submit comments on the proposed EOP-011-1. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller, Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
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Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Individual or group. (40 Responses)
Name (24 Responses)
Organization (24 Responses)
Group Name (16 Responses)
Lead Contact (16 Responses)
IF YOU WISH TO EXPRESS SUPPORT FOR ANOTHER ENTITY'S COMMENTS WITHOUT ENTERING ANY ADDITIONAL COMMENTS, YOU MAY DO SO HERE. (1 Responses)
Comments (40 Responses)
Question 1 (38 Responses)
Question 1 Comments (39 Responses)
Question 2 (37 Responses)
Question 2 Comments (39 Responses)
Question 3 (35 Responses)
Question 3 Comments (39 Responses)
Question 4 (36 Responses)
Question 4 Comments (39 Responses)
Question 5 (26 Responses)
Question 5 Comments (39 Responses)
Question 6 (28 Responses)
Question 6 Comments (39 Responses)
Question 7 (27 Responses)
Question 7 Comments (39 Responses)
Question 8 (34 Responses)
Question 8 Comments (39 Responses)
Question 9 (34 Responses)
Question 9 Comments (39 Responses)
Question 10 (36 Responses)
Question 10 Comments (39 Responses)
Question 11 (28 Responses)
Question 11 Comments (39 Responses)
Question 12 (32 Responses)
Question 12 Comments (39 Responses)
Question 13 (31 Responses)
Question 13 Comments (39 Responses)
Question 14 (33 Responses)
Question 14 Comments (39 Responses)
Question 15 (30 Responses)
Question 15 Comments (39 Responses)
Question 16 (31 Responses)
Question 16 Comments (39 Responses)
Question 17 (34 Responses)
Question 17 Comments (39 Responses)

Individual
Thomas Foltz
American Electric Power
Yes
No
AEP believes R1.2.4 (Processes for redispatch of generation) is applicable to the Balancing Authority, and *not* the Transmission Operator (who does not redispatch generation).
No
AEP does not endorse the current draft of EOP-011-1 R1.2.5 as it is too prescriptive. There could be situations where it is desirable to use UVLS instead of manual load shed since an operator could not shed load fast enough. As a concrete example, consider a situation where there are two major 138kV feeds into an area. If one feed is out of service, and the other were to trip, there would be severe voltage depression with the only the subtransmission support unless UVLS is quickly utilized. It is not clear what the SDT intention is with 1.2.5 as it relates to minimizing risk to the Bulk Electric System.
Yes
Yes
No
In the FERC Order No. 693, Paragraph 632 (EOP-006-1), FERC has clearly directed that the Reliability Coordinator be involved in the development and approval of restoration plans. However, FERC did not make this distinction that the Reliability Coordinator approve the EOP (EOP-001-0) plans (Paragraph 547).Rather than what is currently proposed, the RC needs to be involved in the development and coordination of Emergency Operating Plans as opposed to approving those plans.
No
AEP believes R5 violates Paragraph 81 Criteria B7, as it is redundant with similar requirements in TOP-001-1a R5. The SDT needs to review the existing standards landscape for additional, potential redundancy.

Yes
Individual
Ronnie C. Hoeinghaus
City of Garland
Yes
Yes
Yes
Yes
No
Concern – TOP Operators have full authority and responsibility to deal with emergencies. Also, it is second nature for the operator to notify the RC as soon as he or she is able. Because an emergency is an “emergency”, 1) the operator may be fully occupied dealing with the emergency in real time, 2) may not know the initiating factor that started the emergency until technical personnel (IT, substation, engineering, etc.) investigate, and 3) may not know or be able to “project system conditions”. The concern is that an auditor could say, I listened to the phone recordings, I heard you notify the RC of the current conditions as you knew them but I did not hear you give any projections of return to normal or the system will be in this or that condition in 2 hours or etc. – you are therefore in violation of R5. Recommendation – end the sentence with “communicate the Emergency and the current status.” The RC should have full visibility of the system and see outaged or overloaded elements. If the RC needs additional information beyond what is given, he can question the TOP Operator.

No
Concern - Do not see a benefit to BES reliability or security from revising the Alert levels that would justify the large amount of administrative man-hours that would have to be expended at both the ISO level and at the Registered Entity level. In ERCOT and probably other ISOs, the ISO utilizes Protocols and Operating Guides to operate the various functions of the electric system. Both of these will have to be revised as they both currently reflect the current Alert levels in EOP-002 Attachment 1. Registered Entities also have procedures detailing that Entity's course of action when a RC issues a certain Alert level which would have to be rewritten. Additionally, anyone who has anything to do with electric system operations knows what the current Alert levels are, what they mean, and what actions are to be taken. If the Alert levels are changed, then everyone has to be retrained. Recommendation: Leave the current Alert levels the same. ERCOT has 3 pre-alert notifications based on actual or projected system conditions (Operating Condition Notices, Emergency Advisories, and Emergency Watches) - all designed to communicate prior to reaching the first Alert level that there are concerns about a potential energy deficiency. I have to believe that other ISOs have similar pre-alert notifications though the naming conventions probably vary.
Yes
Agree with this but do not agree with revising Alert levels - see comments on question 15
Individual
Ayesha Sabouba
Hydro One
Yes
Yes
Yes
Yes
Yes
No
The Balancing Authority should gain documented approval from the Load Serving Entity as part of their coordination.
Yes
Yes

Yes
Yes
Yes
No
There should be a maximum time by which the RC must notify impacted parties; it cannot be left stating "as soon as practicable".
Yes
Yes
Yes
Yes
Yes
In the section of the standard entitled “Definitions of Terms Used in Standard”, the SDT has defined Energy Emergency as: “Energy Emergency – a Condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide its customers’ expected energy Load requirements”. This definition is also in the NERC Glossary. This statement is unclear because it does not define the point at which the Load-Serving Entity or Balancing Authority should decide that they can no longer provide expected Load requirements. Is that when they can no longer provide all necessary Load requirements? Or is it intended to mean that a significant portion of the Load requirements can no longer be provided – and if so, what constitutes a significant portion? More clarity is needed in the standard. Even if it is preferable not to define the specific point in the standard, the standard should state that the Energy Emergency condition will be defined and documented by the Balancing Authority or the Load Serving Entity.
Group
Arizona Public Service Company
Janet Smith
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
Group
MRO NERC Standards Review Forum
Joseph DePoorter
Yes
No
Since R1.1 is part of the Operating Plan, an entity does not need a “Definition of” roles and responsibilities. Recommend to remove “Definition of” in R1.1. R1.2, Since an Operating Plan is defined as a procedure or process, recommend deleting “Procedures, processes or” from

R1.2. R1.2.2 should contain the cancelling or recalling of generation outages too. R1.3, recommend to add “topology or System configuration” at the end of R1.3. This further defines that a major change will need to be accomplished in order to review your Emergency Operating Plan. Note that this Requirement (Federal Law) gives the entity a bright line to when a change has to me made. The entity can make any change at any time regardless of this bright line criteria.
No
We believe that the “automatic Load shedding” is either UFLS or UVLS (and maybe an SPS/RAS). It is very hard to (and impossible) “coordinate” an automatic system with a manual system. Since R1.2.5 is an element of the Emergency Operating Plan, recommend R1.2.5 to read: Manual Load shedding plan(s) incorporated to minimize the use of automatic Load shedding;”. This will allow the entity to have a preconceived (pre-planned) process for when the risk is higher that an automatic Load shedding may occur
Yes
No
Since R2.1 is part of the Operating Plan, an entity does not need a “Definition of” roles and responsibilities. Recommend to remove “Definition of” in R2.1. R2.2, Since an Operating Plan is defined as a procedure or process, recommend deleting “Procedures, processes or” from R2.2. R2.3, recommend to add “topology or System configuration” at the end of R2.3. This further defines that a major change will need to be accomplished in order to review your Emergency Operating Plan. Note that this Requirement (Federal Law) gives the entity a bright line to when a change has to me made. The entity can make any change at any time regardless of this bright line criteria.
No
We believe that the “automatic Load shedding” is either UFLS or UVLS (and maybe an SPS/RAS). It is very hard to (and impossible) “coordinate” an automatic system with a manual system. Since R2.2.8 is an element of the Emergency Operating Plan, recommend R1.2.5 to read: Manual Load shedding plan(s) incorporated to minimize the use of automatic Load shedding;”. This will allow the entity to have a preconceived (pre-planned) process for when the risk is higher that an automatic Load shedding may occur.
Yes
Yes
Yes
Yes
Yes

Yes
No
R8 is based on the entity having time to perform the steps in the Emergency Operating Plan. As we know system conditions can change so fast that the entity's involved may have to skip steps in their plan to mitigate the emergency. Recommend R8 to read; The BA shall request its RC to declare a NERC EEA after the BA has EITHER performed the steps in its Emergency Operating Plan OR is unable to resolve the capacity or Energy Emergency condition.
No
Since LSE is included in R9, it will need to be added throughout the Standard, where applicable.
Yes
Yes
Yes
We appreciate the efforts of the SDT and the FYRT to consiladiate the 3 existing standards from the EOP group into a single standard that is clearer and the requirements are organized by Functional Entity.
Individual
Dave Willis
Idaho Power Company
Yes
Consolidation of the three standards is good, the less redundant standards the better.
Yes
The minimum set of requirements is fine. I question that the plan needs to be approved by the Reliability Coordinator. If during an audit a plan is found to be deficient by the auditors but has been approved by the Reliability Coordinator where does the liability fall, With the Transmission Operator or the RC as the approver of the plan? 1.2.4. Redispatch of Generation- seems more like a BA function than a TOP function.
No
No. Automatic load shedding would include under-voltage and under-frequency load shedding which would happen as the result of relay operation. An Operator may not have adequate time to manually shed load to prevent automatic load shedding. The automatic schemes are in place to protect the BES as they should be. I think the requirement should not focus on coordination as much as having a manual load shedding plan. As part of 1.2, it should say "Processes for manual load shedding."
Yes

No
Some environmental constraints are required to comply with at all times. For these constraints, NERC cannot dictate their violation. Redispatch of generation should be a BA function.
No
This coordination may infact require to shed load manually that was included in the Automatic Load Shedding plan. We believe the Balancing Authority should have adequate load shedding capability and capacity. As part of 2.2, it should just say "Processes for manual load shedding."
No
An entity could lean on the interconnection for up to 30 minutes per the proposed BAL-001-2 as long as the interconnection was stable. BAL-002-1 says that the BA shall return its ACE to zero or the pre-disturbance point if ACE was negative within 15 minutes. This requirement needs to be more specific possibly using 30 minutes as in the proposed BAL-001-2.
Yes
No
Agree that the plans should be coordinated but I do not believe that the RC should formally approve the plan. If by approval the RC is saying they have performed R3 "Each Reliability Coordinator shall coordinate the Emergency Operating Plans of the entities in its Reliability Coordinator Area to ensure that the plans are compatible and support reliability in the Reliability Coordinator Area" and not found any incompatibilities or reliability concerns.
Yes
Yes
Yes
Yes
Yes
No
No need to create an Alert 4 category. The existing alerts 0-3 seem to be adequate.
Yes
No need to create an Alert 4 category. The existing alerts 0-3 seem to be adequate.
Yes
When Capacity Emergencies are mentioned they are not capitalized, it is a NERC defined term. Example: R2. Each Balancing Authority shall develop, maintain, and implement a

Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include
Individual
Amy Casuscelli
Xcel Energy
Yes
Xcel Energy supports moving to a single standard as it will leave less room for potential conflicts between multiple documents.
No
R1 and R2 language is strict in that an entity's EOP "shall include" elements defined in R1.1 to R1.3 and R2.1 to R2.3 respectively. What will happen in a situation where one of those elements does not apply to an entity? This standard is implying that all the elements identified in R1.1 to R1.3 and R2.1 to R2.3 must be included in the EOP whether they are applicable or not. The current EOP-001 R4 allows for in its Attachment 1 to be omitted if they are not applicable ("shall include the applicable elements"). We feel like the new EOP-011 standard should include similar language to allow for this flexibility. Could the Standard Drafting Team respond why the language in EOP-011 R1 and R2 was written to be more restrictive than the current EOP-001 R4 and whether items in R1.1 to R1.3 or R2.1 to R2.3 could be omitted from an EOP if found to be not applicable to an entity? Additionally, the word "develop" should be removed from the requirement. Every entity should have a plan today. It should be maintained and implemented. IF an entity does not have a plan, it will have to develop one to have one to implement. The requirement does not need to address this issue.
No
There is no defined performance because of the use of the word "minimize". Does this mean any use of automatic load shedding violates the standard? If so, entities should remove any automatic load shedding capability so they do not violate the standard. However, that will put the interconnection at greater risk, which is not the goal of the standards. As written, there is no clear measurement process. It would have to be argued on a case by case basis and an auditor/regulator can argue any automatic load shedding violates the standard. This is a detail that can not be properly addressed in a standard as the specifics will vary with each entity.
Yes
The time frame is determined by the emergency. The current language is impossible to fairly enforce. Therefore, it should be removed. We support the drafting team's position on this issue.
No
R1 and R2 language is strict in that an entity's EOP "shall include" elements defined in R1.1 to R1.3 and R2.1 to R2.3 respectively. What will happen in a situation where one of those elements does not apply to an entity? This standard is implying that all the elements identified in R1.1 to R1.3 and R2.1 to R2.3 must be included in the EOP whether they are

applicable or not. The current EOP-001 R4 allows for in its Attachment 1 to be omitted if they are not applicable (“shall include the applicable elements”). We feel like the new EOP-011 standard should include similar language to allow for this flexibility. Could the Standard Drafting Team respond why the language in EOP-011 R1 and R2 was written to be more restrictive than the current EOP-001 R4 and whether items in R1.1 to R1.3 or R2.1 to R2.3 could be omitted from an EOP if found to be not applicable to an entity? Additionally, In Requirement 2.2.4. it is unclear what “Governmental programs” is referring to. This term is not descriptive enough in this context to understand clearly what is being asked for. This appears to be a carry over from EOP-001 Attachment 1 Item 12 Requests of government which reads “Requests to appropriate government agencies to implement programs to achieve necessary energy reductions.” If this is the case, we suggest that the language in R2.2.4 be modified to “Governmental programs to reduce Load”. Additionally, the word “develop” should be removed from the requirement. Every entity should have a plan today. It should be maintained and implemented. IF an entity does not have a plan, it will have to develop one to have one to implement. The requirement does not need to address this issue.
No
There is no defined performance because of the use of the word “minimize”. Does this mean any use of automatic load shedding violates the standard? If so, entities should remove any automatic load shedding capability so they do not violate the standard. However, that will put the interconnection at greater risk, which is not the goal of the standards. As written, there is no clear measurement process. It would have to be argued on a case by case basis and an auditor/regulator can argue any automatic load shedding violates the standard. This is a detail that can not be properly addressed in a standard as the specifics will vary with each entity.
Yes
The time frame is determined by the emergency. The current language is impossible to fairly enforce. Therefore, it should be removed. We support the drafting team’s position on this issue.
No
It is unclear how the RC will coordinate plans that will be addressing different issues and owned by different entities. Will the RC require that the entities only use a certain section of their plan if another entity is also experiencing an emergency at that time? While we support the intent of this requirement, it may need a guideline or other guidance document to help the process flow.
Yes
Yes
No
In the current EOP standards, a Load-Serving Entity can as for an EEA from the RC. As written, the LSE is not mentioned. Is the SDT therefore assuming that the BA must provide service to

all loads within its area under its emergency plan regardless of generator ownership or load service responsibility?
No
No, as proposed, the emergency plan will include a process to include manual load shedding. As written, R8 says that the BA can only ask for the RC to declare an EEA after it has completed the steps in the plan. So the BA must cut interrupt loads before the RC can declare an emergency. That should not be the intent of the standard. Additionally, R8 appears to conflict with R9. R8 tells the BA to request that the RC declare an emergency only after it has completed the steps in its plan. R9 tells the RC to declare an emergency if the BA or LSE is either experiencing an emergency or a potential emergency. So the RC must declare an emergency when the BA is potentially experiencing the emergency, but the BA can only request the RC declare after all steps of the plan have been completed. By the time the BA has completed the steps in its plan, the RC must have acted under R9. Requirment R8 should be removed from the proposed standard. The BA already has an obligation to notify the RC under R7 that it is experiencing trouble. There is no need to have the BA call back to request that the RC do something that the RC can do on its own and is required to do under the proposed R9.
No
The answer to this question is dependent upon how the drafting team addresses the conflict between R8 and R9 identified in question 13 above.
No
The drafting team needs to modify the attachment further. The attachment should use defined terms or periods in order to ensure clarity. As an example, what is the “operating window” used under the Alert 1 section? Is it the next hour, next day, or next week? The attachment must provide clarity if it is to be included with the standard.
Yes
This could be preferential to the current attachment. Since the current attachment needs significant work, this process might address our concerns in a better way than the current proposal.
Yes
Xcel Energy appreciates the efforts of the drafting team to date and believes the consolidation of standards is an improvement. The drafting team has addressed many of the issues currently identified with the existing standards. We look forward to additional improvements in the next revision of the draft standard.
Individual
Michael Falvo
Independent Electricity System Operator
Yes

Yes
Yes
We agree with the need to coordinate manual load shedding with other load shedding actions, but Part 1.2.5 appears to fall a bit short of with whom or with which plans a TOP needs to coordinate its manual load shedding plan. We suggest to expand this part as follows: 1.2.5 Manual Load shedding plan coordinated with automatic loading programs to minimize the use of automatic Load shedding, and the manual load shedding plans of other entities in the Reliability Coordinator Area to avoid insufficient or excessive manual load shedding.
Yes
We agree with not specifying a time frame since the time required to implement and complete manual load shedding will depend on a number of conditions, such as: the completion of the automatic load shedding and its effects on mitigation, the time needed for manual load shedding to be completed from the time of initiation, other available actions that may be taken prior to shedding load, etc. The reliability driver is to arrest/mitigate Emergency as soon as possible. System Operators will have this reliability driver in mind when faced with an Emergency, and are the best judge to determine when should manual loading be initiated and completed.
Yes
No
Same comments on R1.2.5 under Q3 on the need to expand this part to more clearly stipulate with whom or which plans a BA needs to coordinate its manual load shedding plan.
Yes
Same comment for Part 1.2.5 under Q4, above.
Yes
We support the proposed requirement, and we agree with the intent of R3 and R4 (to have Emergency Operating Plans by the TOPs and BAs coordinated, and approved by the RC). However, we believe putting the coordination responsibility solely to the RC (as Requirement R3 so suggests) is not sufficient or appropriate. The TOPs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other TOPs and BAs in the RC Area. Likewise, the BAs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other BAs and TOPs in the RC Area. The RC’s role, then, will be to assess if such coordination occurred, and approve or disapprove the EOPs. We suggest R3 be revised to explicitly state the responsibilities for the TOPs and the BAs (or any other entities within the RC’s Area) to coordinate their EOPs. Alternatively, a new requirement may be created to capture such responsibilities.
Yes
We agree the proposed R4, on the assumption that coordination between TOPs/BAs have occurred prior to the submittal of the individual EOPs. Please refer to our comments/suggestions under Q8, above.

Yes
We support the addition of R5 to have a Transmission Operator that is experiencing an operating Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. We are indifferent as to who should be responsible for communication this to other TOPs and/or BAs that may be impacted by the TOP's Emergency, for so long as this is performed by a responsible entity.
Yes
We are indifferent as to who should be responsible for communication this to other TOPs and/or BAs that may be impacted by the TOP's Emergency, for so long as this is performed by a responsible entity.
Yes
We are indifferent as to who should be responsible for communication Emergency in a TOP or BA within a RC Area to those entities that are impacted or could be impacted, for so long as this is performed by a responsible entity. Holding the RC responsible for this communication is more streamlined and coordinated, but it adds time to complete the communication. Holding the individual entities whose area is experiencing Emergency can speed up information dissemination, but may cause confusions.
Yes
Yes
No
While the initial Attachment 1 is largely intact, we notice that the notification details under an Alert 2 have been removed. The mapping document does not provide the rationale for the removal, nor is it presented in any of the technical justification document. We see the need for having such details in the revised Attachment 1, but are not provided the basis of the removal to aid an assessment. Please provide the rationale.
No
We can support defining the EEA levels through a definition, and incorporate them into the NERC Glossary. However, Attachment 1 also serves the purpose of providing necessary information associated with and required for issuing EEAs. To put some of that into the glossary of term, it will make the defined term very lengthy. And putting other information into a guideline document is only possible if none of the required information depicted in Attachment 1 is mandatory. Unfortunately, we are unable to locate the detailed technical justification the EOP SDT used to support the proposed removal of all information in Attachment 1 that are "requirements". Please provide them at the next posting so that we can assess the merit of this proposal. A mapping of the detailed information in Attachment 1 after the proposed removal will be very helpful.
Yes
We are unclear on the inclusion of "BAL-002-WECC-2 – Contingency Reserve" and Requirement R1 on P. 3, Definitions of Terms Used in Standard. Please clarify.

Individual
John Seelke
Public Service Enterprise Group
Yes
Yes
No
The requirement for a coordinated manual Load shedding plan is a good one. However, the TOP should coordinate its plan with its LSEs, DPs, and their respective BAs. BAs should be added to the TOP coordination because a manual Load shedding plan is also required in R2 for BAs. The two entities (TOP and BA) should coordinate their manual Load shedding plans among themselves before submitting such plans to their RC for approval. Part 1.2.5 should therefore be modified as follows: “Manual Load shedding plan coordinated [ADD: among its Load Serving Entities and Distribution Providers and their respective Balancing Authority(ies) ….]”
Yes
As described in our response to question 17 that addresses changes to Alert Level 2, change 2.2.7 as follows: “Use of [STRIKE:Interruptible Load, curtailable Load and demand response][ADD controllable and dispatchable Demand Side Management Load];”
No
The requirement for a coordinated manual Load shedding plan is a good one. However, the BA should coordinate its plan with its LSEs, DPs, and their respective TOPs. TOPs should be added to the BA coordination because a manual Load shedding plan is also required in R1 for TOPs. The two entities (TOP and BA) should coordinate their manual Load shedding plans among themselves before submitting such plans to their RC for approval. Part 2.2.8 should therefore be modified as follows: “Manual Load shedding plan coordinated [ADD:among its Load Serving Entities and Distribution Providers and their respective Transmission Operator(s)] ….”
Yes
Yes
Yes
Yes
Yes

Yes
Yes
R8 should reference Attachment 1 – EOP-011. It should be modified to say The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert [ADD: per Attachment 1-EOP-011-1]….
No
LSEs should not be subject to the standard since their BAs are subject to it. R9 should be modified to eliminate phrase “a Load Serving Entity.” See our response in question 17, paragraph 2, which provides additional justification for this deletion.
No
We recommend the following changes to Attachment 1-EOP-011-1: 1. Consistent with our request in paragraph 2.a. in question 17 below to remove LSE from the definition of Energy Alert, please delete “Load-Serving Entity” from first paragraph and also the second paragraph that defines an “Energy Deficient Entity.” 2. Combine Alert 2 and Alert 3 into one single Alert 2. Demand response resources are a part of a BA’s total resources that includes generation resources. Alert 2 now says “All available resources in use” which is not factually correct unless demand response resources are included. Alert 2 is proposed to be changed as shown below. (For the SDT’s information, the phrase “controllable and dispatchable Demand Side Management Load” used below is taken from the definitions of “Demand Side Management” and “Total Internal Demand” in MOD-031-1 that is under development in Project 2010-04 Demand Data (MOD C).) SUMMARY OF PROPOSED CHANGES TO ALERT 2 2. Alert 2 – All [ADD:forecasted] available resources (generation and controllable and dispatchable Demand Side Management Load) are committed [ADD: and interruption of Firm Demand is imminent]. Circumstances: • Energy Deficient Entity is experiencing conditions where all available resources (generation and controllable and dispatchable Demand Side Management Load) are committed to meet [STRIKE:firm Load][ADD: Firm Demand], firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves. • (Deleted the first bullet under Alert 3.) • Energy Deficient Entity has implemented its approved Emergency Operations Plan. During Alert 32, Reliability Coordinators, Balancing Authorities and Energy Deficient Entities have the following responsibilities: OTHER CHANGES: Change the “3” in 3.1 through 3.5 to “2” so that “3.1” becomes “2.1, etc.” Make similar changes to 3.5.1 through 3.5.3. In addition, change the language in existing 3.5.2 as follows [STRIKE:3][ADD:2].5.2 Initiate [STRIKE: contractually interruptible Loads and demand-side management curtailed][ADD:interruption of controllable and dispatchable Demand Side Management Load.] Initiate [STRIKE: contractually interruptible retail Loads curtailed, and demand-side management activated][ADD:interruption of non-Firm Demand] within provisions of their agreements. 3. Make these changes to Alert 4 follows: SUMMARY OF PROPOSED CHANGES TO ALERT 4 [ADD:3.] Alert [STRIKE:4][ADD:3] - [ADD:Firm Demand][STRIKE:Load] interruption [STRIKE: imminent or] in progress. OTHER CHANGES: Change the first bullet to “Energy Deficient Entity” [STRIKE: foresees or] has implemented interruption of [ADD:Firm Demand][STRIKE:firm Load obligation interruption]. Change the “4”

in 4.1 through 4.4 to “3” so that “4.1” becomes “3.1,” etc.” Also change “4.4.1” to “3.4.1.” In existing 4.1, change “Alert 4” to “Alert 3” in two places.
No
It is unclear how a new Glossary term for Energy Emergency Alert would be defined by the SDT and what would remain in Attachment 1 as guidance. We would need to see the proposed EEA definition and a revised Attachment 1.
Yes
1. The Emergency Operating Plans developed under R1 and R2 may contain Critical Energy Infrastructure Information (CEII). There should be a requirement that if such plans contain CEEI, (a new term that would need to be defined in the NERC Glossary but which FERC has defined) such information should be redacted before making the plans available in a public domain. Furthermore, such plans should be maintained by entities in a manner consistent with the treatment of CEII. 2. We recommend two changes in the definition of Energy Emergency: a. Eliminate the reference to Load-Serving Entity and just reference Balancing Authority. The LSE’s BA should, through R9, be the lowest level entity that experiences an Energy Emergency. A BA that dispatches for several LSEs may be able to resolve an LSE energy emergency issue, and if it cannot, the BA should act under R9. See our response to question 14 that also recommended deletion of Load Serving Entity from R9. b. A NERC Glossary term is already defined for “Firm Demand.” We therefore recommend that “Firm Demand” replace “Load.” There is no Energy Emergency when a BA expects to interrupt non-Firm Load. With these changes, “Energy Emergency” would be defined as “A condition when a Balancing Authority has exhausted all other options and can no longer provide its customers’ expected Firm Demand requirements.”
Group
Dominion
Connie Lowe
Yes
No
Part 1.2.6 says ‘Strategies to be used to mitigate reliability impacts of extreme weather conditions.’ Part 2.2.9 says ‘Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan.’ Dominion suggests revising Part 1.2.6 to read “Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan.” which has the same caveat for coverage by other elements of the plan as Part 2.2.9.
No
Dominion is concerned that this could be read as requiring manual (human at station) load shed as opposed to automatic (SCADA) when we believe the intent is to coordinate so as to avoid overlap with UFLS and UVLS programs. We suggest 1.2.5 read as ‘Operator controlled

manual Load shedding plan coordinated to minimize the use of UFLS and UVLS automatic Load shedding.' In which operator controlled manual load shedding was used in EOP-003-2.
Yes
No
The last sentence in R2 Dominion suggests adding "the following elements:" for consistency with R1. What is meant by Governmental programs in 2.2.4, this needs more description or some examples? Are governmental programs exclusive of 2.2.2, 2.2.3 and 2.2.7 and if so, why are they exclusive? EOP-001-2.1b Attachment 1 says "12. Requests of government — Requests to appropriate government agencies to implement programs to achieve necessary energy reductions." This seems to be a type of energy reduction which is covered in 2.2.7, therefore Dominion suggests removing 2.2.4.
No
Dominion is concerned that this could be read as requiring manual (human at station) load shed as opposed to automatic (SCADA) when we believe the intent is to coordinate so as to avoid overlap with UFLS and UVLS programs. We suggest 2.2.8 read as 'Operator controlled manual Load shedding plan coordinated to minimize the use of UFLS and UVLS automatic Load shedding.' In which operator controlled manual load shedding was used in EOP-003-2.
Yes
Yes
Yes
Dominion believes the SDT is assuming the 'plans are submitted on an agreed-upon schedule', there is nothing in the standard that requires this, but we agree 30 days is adequate.
Yes
Yes
Yes
No
Dominion believes R8 should be included as a sub-requirement in R2, we do not believe it qualifies as a standalone requirement.
No
Dominion suggests that Load-Serving Entity be removed from this requirement. If the SDT wants to require that a LSE experiencing a potential or actual Energy Emergency notify an entity, that entity should be its BA (therefore suggest this be included as a sub-requirement to R2). Dominion does not believe that such a requirement or sub-requirement is necessary and would suggest that this decision be left to each BA.

No
Dominion believes the reporting hierarchy should be preserved so that only BA and TOP communicate with the RC. Entities that may be, or are, energy deficient (LSE) should have to communicate that information to their BA. The BA's Emergency Operating Plan (R2) should include one or more steps to request its Reliability Coordinator to declare a NERC Energy Emergency Alert as necessary (there are 3 levels, we think there probably needs to be multiple steps and a request at each level).
Yes
Yes
M1 contains "that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability Coordinator," this also needs to be included in M2.
Individual
Michelle D'Atnuono
Ingleside Cogeneration LP
Yes
Ingleside Cogeneration LP (ICLP) supports the project team's efforts to clearly separate compliance responsibilities by entity. In our view, the mixing of TOP and BA requirements in the existing standards has only served to introduce confusion – leading the possibility open that both or neither entity will take these actions. This leads to a reliability gap that we believe EOP-011-1 successfully addresses.: Ingleside Cogeneration LP (ICLP) supports the project team's efforts to clearly separate compliance responsibilities by entity. In our view, the mixing of TOP and BA requirements in the existing standards has only served to introduce confusion – leading the possibility open that both or neither entity will take these actions. This leads to a reliability gap that we believe EOP-011-1 successfully addresses.

Yes
As a GO/GOP, ICLP would like to reinforce the project team's decision to defer work on generator-related extreme weather preparedness. The issue has been fully vetted under other project headings – and will be actively re-reviewed in the gas/electricity interdependency initiative that FERC is driving. Furthermore, the local regulatory authorities are aggressively taking the lead on winterization planning. In our specific case, the Texas PUC has already required that we submit detailed winterization plans for a quality assessment – and any addition to the EOP requirements would just increase our administrative overhead. We are aware that the priority on this topic may change as a result of the series of winter storms that North America experienced earlier this year, but it is premature to rush the process at this point. There are several high visibility standard development efforts that are competing for our resources – CIP Version 5 comes immediately to mind – and the effect of the recently approved generator validation standards has yet to be determined. As such, we believe the strategy taken in the initial draft of EOP-011-1 is sufficient as it stands; and that that the issue of generator winter preparedness is being actively and effectively pursued elsewhere.
Individual
Shirley Mayadewi
Manitoba Hydro
Yes
Yes
No
(1) R1.2.5 contains a requirement that manual Load shedding be coordinated, but does not specify with whom the Load shedding should be coordinated. The coordinating entities should be specified.
Yes
Yes
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Yes
No
(1) Attachment 1: This Attachment states that “NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements and nothing in these procedures should be interpreted as changing those obligations.” This provision is both unclear and problematic for Canadian registered entities. First, the reference to “FERC-approved tariffs and other agreements” is inappropriate. Canadian tariffs are not regulated or approved by FERC, unless the Canadian entity has market-based rate authorization from FERC. In some cases tariffs are approved by Canadian regulators and in other jurisdictions they are authorized under provincial law. Furthermore, most Canadian energy sale agreements are either not approved by a regulator or only approved to the extent that they involve an international export. More importantly, if this clause in the attachment was intended to state that the standard does not override tariffs and agreements in the event of a conflict, then such wording would not be legally effective in Canada where a single regulator does not perform the function of approving Canadian tariffs, energy sale agreements and NERC standards, thereby having the power to reconcile conflicts. In Canada this would be a matter of statutory provisions on point and may vary from province to province. Legislation governing NERC standards may take precedence over contracts and tariffs. Therefore, this provision should be deleted
Yes
Yes
(1) The term “BAL-002- WECC -2-Contingency Reserve” is included in the definition section, yet is not a defined term that is used in the standard. This should be deleted. Alternatively, if the terminology is not deleted, there is a drafting inconsistency in R1.2 and R1.3. In these sections the term “load” is not capitalized as it is elsewhere in the standard, thereby implying a different meaning than the term “Load” as defined in the NERC Glossary. If the same meaning was intended, this term should be capitalized. Also, in R1.3, the reference to the U.S. Code of Federal Regulations is inappropriate for non- FERC jurisdictional NERC registered entities. Since Canadian entities are not bound by U.S. law, the reference should be deleted or confined to U.S. registered entities. (2) The definition of “Emergency Energy “refers to a condition where “all other options” have been exhausted. However, since the definition does

not refer to any options, it is not clear what the phrase “other options” refers to. This should be clarified. For instance, is the intention to refer to all options other than manual Load shedding?
Individual
Keith Morisette
Tacoma Power
Yes
Yes
No
Tacoma Power is unsure if the intent is: a) for the System Operator to minimize manually shedding facilities that have automatic load shedding equipment installed in lieu of facilities that do not, -OR- b) to utilize manual load shedding (preemptively) to attempt to forestall automated load shedding from occurring.
No
The current EOP-003-2 R8 language “timeframe adequate for responding to the emergency” should remain. Load shedding plans that are not viable (i.e. the System Operator has no hope of actually executing the plan quickly enough to mitigate the emergency) are useless. Tacoma Power fears that without this measurement, plans that are not actually useful may be created.
Yes
No
Tacoma Power is unsure if the intent is: a) for the System Operator to minimize manually shedding facilities that have automatic load shedding equipment installed in lieu of facilities that do not, -OR- b) to utilize manual load shedding (preemptively) to attempt to forestall automated load shedding from occurring.
No
The current EOP-003-2 R8 language “timeframe adequate for responding to the emergency” should remain. Load shedding plans that are not viable (i.e. the System Operator has no hope of actually executing the plan quickly enough to mitigate the emergency) are useless. I fear that without this measurement, plans that are not actually useful may be created.
Yes
Yes
No

Tacoma Power would suggest the following modification: …operating Emergency to communicate "as soon as practical" its Emergency…
No
Tacoma Power would suggest the following modification: …Energy Emergency to communicate "as soon as practical" its Emergency…
Yes
Yes
Yes
No
Stating there are "three" levels of Energy Emergency Alerts, when there are actually "five" (including Level 0) is a constant source of confusion amongst trainees and junior Operators. In many regions, these standards are something that the Operator only works with during training classes, so we need to remove any confusion where possible. Please fix this.
Yes
Yes
Tacoma Power agrees with the overall idea of combining three Energy and Capacity Emergency related plans into one standard, though we are concerned about expanding the new standard to include the Transmission System Emergencies. Our concern is that this standard might be mis-interpreted and/or mis-applied in an attempt to address any and all Transmission emergencies (emphasis on the lower case "e" in emergencies). We feel the standard development team has done a pretty good job so far in addressing this and hope they keep this concern in mind as they continue to develop this standard.
Individual
Lorraine Landers
Consumers Energy Company
Yes
Agree that the merging of the three standards will provide clarity of the critical requirements and promoting coordination and communication across functional entities
Yes
Yes
Yes

N/A to SC&M Department
N/A to SC&M Department
N/A to SC&M Department
Yes
Yes
Yes
N/A to SC&M Department
Yes
Yes
Yes
N/A to SC&M Department
Yes
No
Group
SPP Standards Review Group
Robert Rhodes
Yes
The work of the SDT in consolidating these standards on emergency operations and clarifying the different requirements between the BA and TOP is appreciated and commendable.
No
We agree with the intent of the SDT to create a separate requirement for Transmission Operators to have an Emergency Operating Plan. Unfortunately, the requirement actually combines three requirements (development, maintenance and implementation) into a single requirement. We recommend splitting each of these into separate requirements. Additionally, the Time Horizon for development and maintenance of the Emergency Operating Plan is different than that for implementation. It may be more appropriate to include implementation of the Emergency Operating Plan to prevent or mitigate operating Emergencies on its Transmission System within R5. Also, the Violation Risk Factors for development and maintenance of the plan should be “Medium”, while the Violation Risk Factor for implementation should be “High”. Corresponding changes to M1 would need to be

made to reflect these proposals. The measurement for implementation is also troubling as registered entities may be in the position of having to prove a negative if they do not have an Emergency during an audit period. Additionally, we request clarification on the intent of the term 'implement' in R1. Does this mean simply disseminating the Plan throughout your organization including providing it to your operators? Or does this mean activating your Plan when an Emergency occurs? If it's the former, then it fits this requirement and we would propose the SDT use 'disseminate' or 'issue' for the term. However, if it is the latter, then it doesn't belong in this requirement but perhaps in R5. It seems that the intent could be the latter since the SDT used implement again in Part 1.1 in conjunction with activate. The Emergency Operating Plan, specified in R1, should include the requirement to notify the TOP's RC of its current and projected System conditions. R5 would then simply require implementation of the plan. (See our comment in Question 10 below.) Part 1.3. is not clear. An emergency plan that includes procedures, processes and strategies, may not need to be revised for every change to the TOP's System. The requirement does not include any periodic review. Is the intent of the SDT that the process include some periodic review or is that entirely up to the TOP? As currently stated, the scope is entirely too broad. In the 2nd line of M1, insert a space between 'R1' and 'that'.
No
The phrase "coordinated to minimize the use of automatic Load shedding" in Requirement 1, Part 1.2.5 is not clear. Is the intent to coordinate the manual Load shedding plan with those locations that have automatic Load shedding installed so as not to duplicate the same Load in both manual and automatic plans? Or is the intent to develop a manual Load shedding plan that will be enacted quickly enough so that automatic Load shedding is minimized? If it is the former, we suggest revised language for Part 1.2.5.: "Manual Load shedding plan coordinated to minimize the use of locations with automatic Load shedding;". We may even go further to propose deleting the phrase "to minimize the use of automatic load shedding" entirely as this seems to be a bit of editorializing. If it is the latter, then the reason for having a manual Load shedding plan is immaterial in the standard. It definitely needs to be in your Emergency Operating Plan, just not in the standard.
No
One of the issues identified in previous events has been that some entities have manual Load shedding plans that require dispatching personnel to dispersed locations to implement the plan. The standard should include a requirement that manual Load Shedding be able to be implemented in time to mitigate the Emergency. We suggest the requirement include that the Manual Load shedding plan be capable of being implemented by an operator remotely. This addresses the issue of not being able to respond quickly to a given situation while at the same time eliminating the ambiguity of maintaining the existing language in EOP-003-2, R8.
No
We agree with the intent of the SDT to create a separate requirement for Balancing Authorities to have an Emergency Operating Plan. Unfortunately, the requirement actually combines three requirements (development, maintenance and implementation) into a single requirement. We recommend splitting each of these into separate requirements. Additionally,

the Time Horizon for development and maintenance of the Emergency Operating Plan is different than that for implementation. It may be more appropriate to include implementation of the Emergency Operating Plan to prevent or mitigate operating Emergencies within its Balancing Authority Area within R6. Also, the Violation Risk Factors for development and maintenance of the plan should be “Medium”, while the Violation Risk Factor for implementation should be “High”. Corresponding changes to M2 would need to be made to reflect these proposals. The measurement for implementation is also troubling as registered entities may be in the position of having to prove a negative if they do not have an Emergency during an audit period. Additionally, we request clarification on the intent of the term ‘implement’ in R2. Does this mean simply disseminating the Plan throughout your organization including providing it to your operators? Or does this mean activating your Plan when an Emergency occurs? If it’s the former, then it fits this requirement and we would propose the SDT use ‘disseminate’ or ‘issue’ for the term. However, if it is the latter, then it doesn’t belong in this requirement but perhaps in R6. It seems that the intent could be the latter since the SDT used implement again in Part 2.1 in conjunction with activate. The Emergency Operating Plan, specified in R2, should include the requirement to notify the BA’s RC of its current and projected System conditions. R6 would then simply require implementation of the plan. (See our comment in Question 11 below.) Part 2.3. is not clear. An emergency plan that includes procedures, processes and strategies, may not need to be revised for every change in the BA’s Balancing Authority Area. The requirement does not include any periodic review. Is the intent of the SDT that the process include some periodic review or is that entirely up to the BA? As currently stated, the scope is entirely too broad. EOP-002-3.1 R5. which states “A deficient Balancing Authority shall only use the assistance provided by the Interconnection’s frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.” does not appear to be covered in R2 as indicated in the Mapping Document. This requirement should be included in this standard or included in the BAL standards in Project 2010-14.2 Periodic Review of BAL Standards. Delete the ‘as’ in the 2nd line of M2 between the ‘have’ and ‘evidence’.
No
The phrase “coordinated to minimize the use of automatic Load shedding” in Requirement 2, Part 2.2.8 is not clear. Is the intent to coordinate the manual Load shedding plan with those locations that have automatic Load shedding installed so as not to duplicate the same Load in both manual and automatic plans? Or is the intent to develop a manual Load shedding plan that will be enacted quickly enough so that automatic Load shedding is minimized? If it is the former, we suggest revised language for Part 2.2.8.: “Manual Load shedding plan coordinated to minimize the use of locations with automatic Load shedding;”. We may even go further to propose deleting the phrase “to minimize the use of automatic load shedding” entirely as this seems to be a bit of editorializing. If it is the latter, then the reason for having a manual Load shedding plan is immaterial in the standard. It definitely needs to be in your Emergency Operating Plan, just not in the standard.

No
One of the issues identified in previous events has been that some entities have manual Load shedding plans that require dispatching personnel to dispersed locations to implement the plan. The standard should include a requirement that manual Load Shedding be able to be implemented in time to mitigate the Emergency. We suggest the requirement include that the Manual Load shedding plan be capable of being implemented by an operator remotely. This addresses the issue of not being able to respond quickly to a given situation while at the same time eliminating the ambiguity of maintaining the existing language in EOP-003-2, R8.
No
While we agree with the intent, the language of the proposed requirement R3 only requires coordination within the Reliability Coordinator Area. Especially for entities on the seams between Reliability Coordinator Areas, it is essential that these plans be coordinated with neighboring Reliability Coordinators. We propose the following language for R3: “Each Reliability Coordinator shall review the Emergency Operating Plans of the entities in its Reliability Coordinator Area and with neighboring Reliability Coordinators to ensure that the plans are compatible and support reliability of the Bulk Electric System.” This proposal also eliminates potential issues with the use of the term ‘coordinate’.
No
While we support the concept of the requirement, we propose a rewording to improve clarity. We suggest: “Each Reliability Coordinator shall approve, or disapprove with stated reasons for disapproval, Emergency Operating Plans submitted by Transmission Operators and Balancing Authorities within 30-calendar days of submittal.” M4 would need to be modified to parallel this language. Additionally, the question refers to an ‘agreed-upon schedule’ for submittal of the plans. We cannot find a reference to this agreement in the standard. Plans will need to be revised and then subsequently submitted for review and approval but there is nothing mentioned about an agreed-upon schedule between the Reliability Coordinator and the Balancing Authority or Transmission Operator. Perhaps the SDT should look at the language contained in EOP-005-2 outlining timing for the submittal and approval of restoration plans by the Transmission Operator and Reliability Coordinator, respectively, for parallels for submitting and approval of Emergency Operating Plans.
No
It may be appropriate to include implementation of the Emergency Operating Plan to prevent or mitigate operating Emergencies on its Transmission System within R5. The Emergency Operating Plan, required in R1, should include the requirement to notify the Transmission Operator’s Reliability Coordinator of its current and projected System conditions. R5 would then simply require implementation of the plan. (See our comments on Question 2.) We recommend the following for R5: “Each Transmission Operator that is experiencing an operating Emergency on its Transmission System shall implement its Emergency Operating Plan. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]”
No
It may be appropriate to include implementation of the Emergency Operating Plan to prevent or mitigate operating Emergencies within its Balancing Authority Area within R6. The

Emergency Operating Plan, required in R2, should include the requirement to notify the Balancing Authority's Reliability Coordinator of its current and projected System conditions. R6 would then simply require implementation of the plan. (See our comments on Question 5.) We recommend the following for R6: "Each Balancing Authority Operator that is experiencing an operating Emergency within its Balancing Authority Area shall implement its Emergency Operating Plan. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]"
No
We recommend including the Load Serving Entity in this requirement as follows: "Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator, Balancing Authority or Load Serving Entity shall notify, as soon as practicable, impacted Reliability Coordinators, Balancing Authorities and Transmission Operators." We feel this is justified based on the statement in the first paragraph of the Introduction of Attachment 1, where the SDT points out that the Reliability Coordinator is responsible for communicating the 'condition' of Balancing Authorities or Load Serving Entities. However, the requirement doesn't include LSE. They need to be included. Additionally, we have some concern with the use of 'as soon as practicable'. We understand that this was inserted to stress the timeliness of this notification but have issues with its measurability. Some standards have used 'without intentional delay' in the past. While not a clear cut remedy, it does appear to be a little better and is consistent with other standards.
No
Although we agree with the concept, the language of Requirement R8 implies that the Balancing Authority only requests an EEA after it has completed the steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. Coordination between the Plan and Attachment 1 is an issue. EEA Alert 1 is to be issued when the Energy Deficient Entity foresees the need to declare an Energy Emergency. Alert 2 is issued when all available resources are in use. Alert 3 is issued when load management procedures are in effect. Alert 4 is issued when firm Load interruption is imminent or in progress. If an entity must first complete the steps in its Emergency Operating Plan (which must include manual Load shedding per R2) and is unable to resolve the capacity or Energy Emergency condition, the first three Alert Levels would have already been past. We suggest incorporating a new Part under Requirement R2.2 that requires the Balancing Authority requesting its Reliability Coordinator to declare Emergency Alert Levels satisfy the criteria for issuing an Energy Emergency Alert as outlined in Attachment 1. There are different Energy Emergency Alert Levels and they are issued at various stages within the event. The Balancing Authority's Emergency Operating Plan should include requesting the Reliability Coordinator to declare each level when conditions have been met for each level. This would eliminate the need for Requirement R8 and yet provide for the notification of the Reliability Coordinator and other impacted entities of the Emergency condition. The new Part 2.3.0 would read: "Utilization of Energy Emergency Alerts as detailed in Attachment 1." R8 could then be deleted.
No

Delete ‘NERC’ in the last line of the Requirement. Change ‘experiencing’ to ‘experience’ in the 2nd line of M9. Also delete ‘NERC’ in the next to last line of M9.
No
We suggest the last line of the 1st paragraph of the Introduction be modified to read ‘Entity within its Reliability Coordinator Area which is experiencing an Energy Emergency.’ Change three levels to four levels in the Introduction under Section B. Energy Emergency Alert Levels. In the 2nd bullet under Circumstances in Section 3. Alert 3 – …, change ‘implemented’ to ‘activated.’ Modify Section 3.4 to read ‘If Transmission limitations are contributing to the Energy Emergency, the Reliability Coordinator should review Transmission outages and work with the applicable Transmission Operator to see if it’s possible to return to service the Transmission element(s) that could relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).’ Modify Section 3.5.2 to read ‘Initiate curtailment of contractually interruptible Loads and activate demand-side management. Initiate curtailment of contractually interruptible retail Loads and activate demand-side management within provisions of the agreements.’ Modify the 2nd and 3rd sentences in Section 4.3 to read ‘Reevaluation of SOLs and IROLs should be coordinated with other impacted Reliability Coordinators and only after agreement has been reached with the Balancing Authority(ies) or Transmission Operator(s) whose equipment would be affected. SOLs and IROLs should only be revised as long as an Alert 4 condition exists, or as allowed by the Balancing Authority(ies) or Transmission Operator(s) whose equipment is at risk. Modify Alert 0 – Termination. to read ‘When the Energy Deficient Entity believes it will be able to supply its customers’ energy requirements, it should request its Reliability Coordinator to terminate the EEA.
No
Unless there is a pressing need to remove the Attachment, we recommend leaving it where it is. This is a known document with many years of use in the industry. We’re familiar with it and know how to use it. The SDT hasn’t really provided any justification for moving it to the Glossary and unless the SDT can help us understand why we need to make the change, we can’t support it. We also have concerns with how the Attachment would be logistically moved into the Glossary. It appears that only part of the document would go into the Glossary and the remaining material would be retained in a guidance document. Splitting the material would degrade the value of the document as it currently exists.
Yes
Background Section: In the 3rd line of the paragraph below the bullet points, spell out Bulk Electric System and then follow it with the BES in parentheses.
Group
Florida Municipal Power Agency
Frank Gaffney
Yes

No
Does the RC really need to approve, or should it be a coordination requirement? If so, then there ought to be a description of what types of changes ought to require approval and what changes do not, e.g., do minor changes such as phone number updates need to be approved?
No
1.2.5 ought to be specific to UVLS and should not apply to UFLS. A TOP has no role in manual load shedding to address a capacity / energy emergency to coordinate with UFLS. It is unrealistic to expect load shedding for purposes of solving local transmission problems to retain enough load in the local area to then be able to participate fully in the UFLS program, e.g., it may be necessary to shed all of the load at a particular substation to solve an overload due to multiple contingencies on the transmission system, which will mean that the UFLS relays on the feeders at that substation will not participate in a subsequent UFLS event. Missing those limited number of UFLS relays will not have a meaningful effect on the effectiveness on a UFLS program which is more regional in nature.
Yes
No
Similar to comments on Question 2, if the RC is retained as an approval authority, then, the standard needs to better describe change management and what changes the RC is to review and approve.
No
Similar to 1.2.5, the automatic load shedding to be coordinated with is UFLS, not UVLS; hence, the bullet should be made specific to the type of load shedding to be coordinated with. It is unrealistic to expect a coordination of load shedding between UFLS and UVLS, that is, in areas where both UVLS and UFLS is needed, there will be overlap of the distribution feeders, i.e., there will be individual feeders that will have both UFLS and UVLS on it.
Yes
Yes
Yes
Yes
The only other issue that may be appropriate to address is timing of the required communication. Maybe something like "as soon as reasonable while not unduly impacting response to the Emergency".
Yes
See comments to question 10.
Yes

Yes
Yes
Yes
No
FMPA would prefer to retain it as an attachment to the standard.
Yes
FMPA appreciates the work of the SDT to vastly improve the standards.
Group
Northeast Power Coordinating Council
Guy Zito
Yes
Yes
No
We agree with the need to coordinate manual load shedding with other load shedding actions, but Part 1.2.5 falls short of with whom or with which plans a TOP needs to coordinate its manual load shedding plan. We suggest expanding this part as follows: 1.2.5 Manual Load shedding plan coordinated with automatic loading programs to minimize the use of automatic Load shedding, and also coordinated with the manual load shedding plans of other entities in the Reliability Coordinator Area to avoid insufficient or excessive manual load shedding.
Yes
There are other standards with requirements in place to mitigate emergency conditions (e.g. IROL violations) in specific time frames. Imposing another time frame creates the potential for having multiple violations for the same infraction. We agree with not specifying a time frame since the time required to implement and complete manual load shedding will depend on a number of conditions, such as: the completion of the automatic load shedding and its effects on mitigation, the time needed for manual load shedding to be completed from the time of initiation, other available actions that may be taken prior to shedding load, etc. The reliability driver is to arrest/mitigate Emergency as soon as possible. System Operators will have this reliability driver in mind when faced with an Emergency, and are the best judge to determine when should manual loading be initiated and completed.
No

Same comments as provided in Question 3 for Part 1.2.5 on the need to expand this part to more clearly stipulate who or which plans a BA needs to coordinate its manual load shedding plan with.
Yes
Same comment as for Part 1.2.5 in the response to Question 4.
No
We support the proposed requirement, and we agree with the intent of R3 and R4 (to have Emergency Operating Plans by the TOPs and BAs coordinated, and approved by the RC). However, we believe putting the coordination responsibility solely on the RC (as Requirement R3 suggests) is neither sufficient nor appropriate. The TOPs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other TOPs and BAs in the RC Area. Likewise, the BAs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other BAs and TOPs in the RC Area. The RC’s role, then, will be to assess if such coordination occurred, and approve or disapprove the EOPs. We suggest R3 be revised to explicitly state the responsibilities for the TOPs and the BAs (or any other entities within the RC’s Area) to coordinate their EOPs. Alternatively, a new requirement may be created to capture such responsibilities.
No
It is not clear what an entity should do if its plan is not approved, especially if an entity is revising its plan to address a known deficiency or required changes to its existing plan. In this circumstance simply using the existing plan does not seem appropriate. We agree with the proposed R4, on the assumption that coordination between TOPs/BAs have occurred prior to the submittal of the individual EOPs. Please refer to our comments to Question 8.
Yes
We support the addition of R5 to have a Transmission Operator that is experiencing an operating Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. (Clarification is needed for “projected system conditions.” A definition of this term would help clarify the intent of this statement so that it would not be open ended.) A responsible entity must communicate this to other TOPs and/or BAs that may be impacted by the TOP’s Emergency. How quickly does a TOP that is experiencing an operating Emergency have to “communicate the Emergency and its current and projected System conditions to its Reliability Coordinator”?
Yes
We are indifferent as to who should be responsible for communicating this to other TOPs and/or BAs that may be impacted by the TOP’s Emergency, as long as this is performed by a responsible entity.
No
There should be a maximum time by which the RC must notify impacted parties; it cannot be left stated “as soon as practicable”. Holding the RC responsible for this communication can be more streamlined and coordinated, but it adds time to completion of the communication. Holding the individual entities whose area is experiencing an Emergency responsible for such

notifications can speed up information dissemination, but may cause confusion. It must considered that an individual entity's top priority should be to resolve the Emergency.
Yes
Yes
No
While the initial Attachment 1 is largely intact, we notice that the notification details under an Alert 2 have been removed. The mapping document does not provide the rationale for the removal, nor is it presented in any of the technical justification document. We see the need for having such details in the revised Attachment 1, but are not provided the basis of the removal to aid an assessment. Please provide the rationale.
No
Both the proposed and current approaches are acceptable. We can support defining the EEA levels through a definition, and incorporate them into the NERC Glossary. However, Attachment 1 also serves the purpose of providing necessary information associated with and required for issuing EEAs. To put some of that into the Glossary of Terms, will make the defined term very lengthy. Putting other information into a guideline document is only possible if none of the required information depicted in Attachment 1 is mandatory. Unfortunately, we are unable to locate the detailed technical justification the EOP SDT used to support the proposed removal of all information in Attachment 1 that are "requirements". Please provide them at the next posting so that we can assess the merit of this proposal. A mapping of the detailed information in Attachment 1 after the proposed removal will be very helpful. The following should be added to the Glossary of Terms as defined terms: "Energy Emergency Alert" "Energy Deficient Entity" Additional comment on Attachment 1, Alert 3 and Alert 0: Shouldn't the words here match the words used in the revised definition of "Energy Emergency" so as to say "is no longer able to meet Load?" (same as under "Alert 0")?
Yes
In the section of the standard entitled "Definitions of Terms Used in Standard", the SDT has defined Energy Emergency as: "Energy Emergency – a Condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide expected Load requirements". This is a revision of the definition in the NERC Glossary is unclear because it does not define the point at which the Load-Serving Entity or Balancing Authority should decide that they can no longer provide expected Load requirements. Is that when it can no longer provide all necessary Load requirements? Or is it intended to mean that a significant portion of the Load requirements can no longer be provided – and if so, what constitutes a significant portion? More clarity is needed in the standard. Suggest revising the definition by changing "provide" to "meet" and delete "requirements". The proposed definition would then read "…can no longer meet its expected Load."Even if it is preferable to not define the specific point in the standard, the standard should state that the Energy Emergency condition will be defined and documented by the Balancing Authority or the Load Serving Entity. Comments on BAL-002-WECC-2 – Contingency Reserve: We are unclear on the

inclusion of “BAL-002-WECC-2 – Contingency Reserve” and Requirement R1 on P. 3, Definitions of Terms Used in Standard. Please clarify. Also, “energy emergency” is not capitalized in one of the R1.1 bullets here – it should be because it is a defined term. “Emergency Operating Plan” is capitalized but it is not a defined term in the Glossary of Terms and there is no definition included in this draft of the standard. A definition should be added or it should not be capitalized. Comment on R1 and R5: the standards talk about “operating Emergencies.” There are definitions for “Energy Emergency,” “Capacity Emergency,” and “Emergency” (or “BES Emergency”). If the definition of “Emergency” captures what is needed, then the word “operating” isn’t needed and should be deleted. The phrase “operating Emergency” also appears in R5. Comment on R2, R6, and R8: Energy Emergency has a definition in the draft – but what constitutes a “capacity” is not capitalized in “capacity Emergency.” The definition of “Capacity Emergency” in the Glossary is “[a] capacity emergency exists when a Balancing Authority Area’s operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.” So, if this is what the standard means by “capacity Emergency,” then it should be capitalized. R2 should read: “to mitigate Capacity Emergencies and Energy Emergencies.” Same comment applies to R6 and R8.
Individual
Andrew Z. Pusztai
American Transmission Company, LLC
Yes
ATC supports the consolidation of the noted EOP standards into the proposed EOP-011-1. However, ATC recommends that Parts R1.2.1 – R1.2.6 and R1.3 of Requirement R1 be rewritten as detailed in the response to Question 2.
Yes
ATC agrees with the wording of the proposed Requirement R1. However, ATC recommends that Parts R1.2.1 – R1.2.6 of Requirement R1 be rewritten as: R1.2.1 – Controlling voltage; R1.2.2 – Cancelling or recalling Transmission outages; R1.2.3 – System reconfiguration; R1.2.4 – Redispatch of generation; R1.2.5 – Manual load shedding designed to minimize the reliance on automatic load shedding; R1.2.6 – Mitigation of reliability impacts of extreme weather conditions; The changes to Parts R1.2.1 – R1.2.6 eliminate references to documentation that is previously specified in Part 1.2 of Requirement R1. The revision of Part 1.2.5 also provides clarification regarding the relationship between manual and automatic load shedding. In addition, ATC recommends that Part R1.3 be rewritten as “A process for reviewing its Emergency Operating Plan on an annual basis to evaluate the impact of changes to its System and revising the Emergency Operating Plan accordingly.” This revision specifies an “annual” time requirement to the Emergency Operating Plan review and revision process.
No
ATC agrees with the wording of the proposed Requirement R1, but recommends that Part 1.2.5 be modified to “Manual load shedding designed to minimize the reliance on automatic

load shedding;" This revision provides clarification regarding the relationship between manual and automatic load shedding.
Yes
ATC supports Requirement R1, Part 1.2.5 without a time measure because time measures are defined in the applicable TOP standards. However, ATC recommends Part 1.2.5 be modified to "Manual load shedding designed to minimize the reliance on automatic load shedding;" This revision provides clarification regarding the relationship between manual and automatic load shedding.
Yes
Yes
Yes
Yes
No
Individual
Anthony Jablonski
ReliabilityFirst
Yes
No
ReliabilityFirst offers the following comments for consideration: 1. Requirement R1 and R2 - ReliabilityFirst believes the "implement a Reliability Coordinator-approved Emergency Operating Plan" language is troublesome in a scenario where a Reliability Coordinator disapproves the Emergency Operating Plan (per Requirement R4). In this scenario, the Transmission Operator/Balancing Authority could be compliant with developing and maintaining the plan but without Reliability Coordinator approval of the plan, the

Transmission Operator/Balancing Authority could potentially be deemed non-compliant with Requirement R1 and R2. ReliabilityFirst believes the “implement a Reliability Coordinator-approved Emergency Operating Plan” language should be taken out of Requirements R1 and R2 respectively. ReliabilityFirst recommends including a new Requirement R5 which states “Upon Reliability Coordinator approval of the Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans, the Transmission Operator and Balancing Authority shall implement the approved Emergency Operating Plan.”
ReliabilityFirst offers the following comments for consideration: 1. Requirement R3 - ReliabilityFirst believes the intent of Requirement R3 (specifically the term “coordinate”) is ambiguous and will lead to potential interpretation problems. ReliabilityFirst believes this “coordination” is actually addressed in Requirement R4 in which the Reliability Coordinators will be reviewing all Emergency Operating Plans and approving/disapproving them accordingly if there are any “coordination” type issues. ReliabilityFirst recommends removing Requirement R3 from the draft standard.
No
ReliabilityFirst offers the following comments for consideration: Requirement R4 - ReliabilityFirst believes if the Reliability Coordinator disapproves an Emergency Operating Plan not only should they be required to state the reasons, they should also be required to provide specific recommended modifications that would lead to the Plan’s approval. ReliabilityFirst recommends the following for consideration “Each Reliability Coordinator shall approve or disapprove, with stated reasons for disapproval [and recommended modifications that would lead to the Plan’s approval], Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans within 30 calendar days of submittal.”
No
ReliabilityFirst offers the following comments for consideration: Requirement R5 - ReliabilityFirst believes there should be a timeframe associated with how long the Transmission Operator has to communicate the Emergency and its current and projected System conditions to its Reliability Coordinator. In a hypothetical situation, without a timeframe associated with the requirement, a Transmission Operator can communicate the Emergency 10 hours after the fact and still be compliant. ReliabilityFirst does not believe this meets the reliability intent of the requirement. ReliabilityFirst recommends the following for consideration: “Each Transmission Operator that is experiencing an operating Emergency on its Transmission System shall communicate the Emergency and its current and projected System conditions to its Reliability Coordinator [within 30 minutes of the start of the Emergency].
No

ReliabilityFirst offers the following comments for consideration: 1. Requirement R6 - ReliabilityFirst has similar concerns with Requirement R6 as stated in the comment to Requirement R5. Also, since Requirement R5 and Requirement R6 are very similar, ReliabilityFirst recommends combining Requirement R5 and Requirement R6 and having them applicable to both the Transmission Operator and Balancing Authority
No
ReliabilityFirst offers the following comments for consideration: 1. Requirement R7 - ReliabilityFirst believes the term "as soon as practicable" is ambiguous, does not provide any added value, and should not be used in standards. This term leaves the requirement open to interpretation and potential problems in compliance monitoring and enforcement. ReliabilityFirst recommends the following for consideration "Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify the impacted Reliability Coordinators, Balancing Authorities and Transmission Operators[, within 30 minutes of the start of the Emergency.]"
No
ReliabilityFirst offers the following comments for consideration: 1. Requirement R9 - ReliabilityFirst believes there should a timeframe associated with how long a Reliability Coordinator has to initiate a NERC Energy Emergency Alert following a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency. ReliabilityFirst recommends the following for consideration: "Each Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate a NERC Energy Emergency Alert, as detailed in Attachment 1[, within 30 minutes of request.]"
Individual
John Brockhan
CenterPoint Energy
Yes
No
CenterPoint Energy has concerns with Requirement R1 as drafted and offers the following recommendations. One, CenterPoint Energy is concerned that, as drafted, Requirement R1 restricts TOPs to one single Emergency Operating Plan. The Company believes TOPs should be able to utilize multiple plans to address R1, as long as the plans in aggregate include all the required elements. Two, CenterPoint Energy does not support requiring the RC to approve the TOP's Emergency Operating Plans. Paragraph 548 of Order 693 only directed that the RC be added as an applicable entity, not for the RC to assume approval responsibility. Thus, to

incorporate suggestions 1 and 2, the proposed Requirement R1 should be revised to state: “Each Transmission Operator shall develop, maintain, and implement one or more Emergency Operating Plans to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plans shall include the following elements:”. Three, CenterPoint Energy believes R1 Part 1.1 is unnecessary. TOP-001-1a Requirement R1 states that Transmission Operators have the responsibility and clear decision-making authority to take whatever actions necessary to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies. TOP 001-1a R2 also states that, “Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment, shedding firm load, etc.” Further definition of roles and responsibilities are unnecessary. CenterPoint Energy recommends R1 Part 1.1 be deleted. Four, CenterPoint Energy believes R1 Part 1.2.1 is duplicative of various existing requirements. TOP-004-2 R6 already requires TOPs to have policies and procedures that address monitoring and controlling of voltage levels that impact reliability. Additionally, VAR-001-3 R1 and R2 require TOPs to have sufficient reactive resources for Contingency conditions and to have formal policies and procedures for monitoring and controlling voltage levels. CenterPoint Energy believes Part 1.2.1 is unnecessary and should be deleted from the proposed EOP-011-1. Five, CenterPoint Energy believes the “extreme weather conditions” referenced in R1 Part 1.2.6 is vague, and it would be challenging for TOPs and auditors to interpret what qualifies as “extreme”. CenterPoint Energy believes that not all events of “extreme” weather result in emergency conditions requiring special mitigation strategies. In addition the Company believes that various existing operational planning requirements are sufficient to cover preparedness for extreme weather, such as TOP-005-2a R2 and Attachment 1 and TOP-006-2 R4. Therefore, Part 1.2.6 is unnecessary and should be deleted. If, however, the SDT insists on retaining such a requirement, CenterPoint Energy recommends Part 1.2.6 be revised to state: “Strategies to be used to mitigate reliability impacts of extreme weather conditions defined by the Transmission Operator.”
Yes
Yes
CenterPoint Energy agrees with the proposed coordination role for the Reliability Coordinator.
No
As stated above in response to Question 2, CenterPoint Energy does not agree with the proposed change to require Reliability Coordinator approval of Transmission Operator’s Emergency Operating Plans. Paragraph 548 of Order 693 directed the ERO to 1) include the RC as an applicable entity, and 2) consider SoCal Edison’s suggestion. The SoCal Edison comment

in Paragraph 546 states that NERC "should receive input from stakeholders on which requirements should be exclusive to the transmission operator or balancing authority with the reliability coordinator responsible only for collecting and incorporating this information into its overarching plan". CenterPoint Energy reading of the directive is that it does not contain the addition of Reliability Coordinator approval and requiring such approval was specifically omitted by the Commission. Therefore, CenterPoint Energy believes this is an unnecessary expansion of FERC's directive in Paragraph 548. CenterPoint Energy strongly recommends Requirement R4 be deleted from the draft standard EOP-011-1.
No
CenterPoint Energy does not believe it is necessary to create a corollary requirement to EOP-002-3.1 R3. Such corollary requirements already exist in standard TOP-001-1a R5 and R8. TOP-001-1a R5 requires the TOP to inform its RC of emergency conditions and to mitigate the emergency if possible, while TOP-001-1a R8 requires the TOP to request emergency assistance from the RC if the TOP is unable to recover on its own. CenterPoint Energy believes the necessary communication between a TOP and its RC to ensure reliability during an Emergency is already mandated. The Company believes the proposed Requirement R5 is redundant based on P81 criteria and should be deleted from the draft standard EOP-011-1.
Yes
Yes
No
CenterPoint Energy does not believe that Energy Emergency Alert levels should be codified in the NERC Glossary and does not support such an approach. The Company believes the NERC Glossary should be reserved for definitions of terms used throughout the Reliability Standards. Terms used in one or two Standards should be defined in the Standard where the term is utilized. CenterPoint Energy recommends keeping Attachment 1 in the proposed EOP-011-1.
Yes
CenterPoint Energy appreciates the work of the SDT and the opportunity to provide comments. CenterPoint Energy cannot support the proposed Standard as it is currently drafted for the reasons stated above. The Company understands this is a first draft and provides these comments in anticipation of being able to support a future version of the Standard.
Individual
Matt Beilfuss
Wisconsin Electric

Yes
Yes
No
It is not clear what or with whom coordination is required. The proposed standard “Rationale for R1” section indicates that TOP and BA load shedding “sometimes” needs to be coordinated. However, neither R1 (TOP requirement) nor R2 (BA requirement) explicitly require coordination between the two.
Yes
No
The RC should not be the approval authority for the BA emergency plan. Given the required minimal inclusions listed in the draft standard, it’s not clear why an RC would need to approve or ensure any type of coordination. As an example, why would an RC have to approve a procedure, process, or strategy for conducting public appeals, government programs, or reduction of internal utility energy use? If an RC has specific points of necessary coordination, why not simply require the RC to develop the elements the entities in their RC area need to coordinate? Changing to the wording of 2.2.1.1 is required; currently it does not flow with 2.2.
No
It is not clear what or with whom coordination is required. The proposed standard “Rationale for R2” section indicates that TOP and BA load shedding “sometimes” needs to be coordinated. However, neither R1 (TOP requirement) nor R2 (BA requirement) explicitly require coordination between the two.
Yes
No
Without the RC identifying the points of coordination, it’s not clear how they can “coordinate” between multiple BAs and TOPs. The standard requires the TOPs and BAs to address specific items in their plans and their plans to be approved by the RC. The timing of TOP/BA submission for RC approval will likely be sporadic and the standard requires the RC to provide approval or disapproval within 30 days. It’s not practical for an RC to coordinate plans from multiple BAs or TOPs submitted at different times without the RC issuing some type of guidance that identifies points of coordination.
Yes
Yes
Yes

Yes
Yes
Yes
Yes
Yes
No
Group
Duke Energy
Michael Lowman
Yes
No
(1)Duke Energy questions the need to require a BA/TOP have its Emergency Operating Plan approved by a Reliability Coordinator. On its face, there doesn’t appear to be a clear Reliability-based need to have an BA/TOP’s individual Emergency Operating Plan approved, and respectfully requests that the SDT provide more clarity on the technical justification for requiring RC-approval. If the Reliability-based need is not readily attainable, the standard/requirement should be viewed as purely administrative in nature, and be treated as unduly burdensome. (2)R1.2.4: As written, R1.2.4 is not clear on what is meant by “Processes for redispatch of generation”. Is it the intent of the SDT to have the TOP work with the other Functions involved? If this is the intent of the SDT, it should be explicitly stated that a TOP must work with other Functions involved for a process on the redispatch of generation. “Process for requesting the redispatch of generation.” (3)The EOP SDT has used the term “Emergency Operating Plan” in R1. as a NERC defined term by capitalizing. Duke Energy believes the intent of this term is to combine the definitions of “Emergency” and “Operating Plan” from the NERC Glossary, but recommends the SDT to take this under consideration. The use of Operating Plan in the requirement is the correct and consistent approach since it is our understanding that the NERC SDT’s have been guided to use defined terms and not use terms such as plan, process, and procedure to eliminate any ambiguity. Because of this approach, Duke Energy questions the use of Plans, Processes, and Strategies in R1.2. and at the beginning of each sub-requirement to R1.2. with the exception of R1.2.5., which has been written differently. The NERC term Operating Plan is defined as, “A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain

Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.” (4)Because the definition of Operating Plan includes “Operating Procedures” and “Operating Processes” (both are NERC defined terms), we recommend the use of these terms in the sub-requirements to be consistent with the direction of other standards that are currently effective or under development. The use of the term “Strategies” will also need to be considered by the SDT to either be replaced with one of the NERC defined terms or propose a new term “Operating Strategies” for comment during the development of Reliability Standard EOP-011-1. (5)R1.2.6: Duke Energy feels as though this requirement is overly broad, and could possibly be viewed as a candidate for Paragraph 81 criteria. Strategies to mitigate reliability impacts of extreme weather are not “one-size fits all”. Not all regions experience the same extreme weather conditions, which could make this requirement difficult to audit against. Duke Energy suggests placing objective and clearly quantifiable measures and VRF/VSL(s) in place to assist a TOP in ascertaining the responsibilities expected for audit purposes. “Identify strategies used to mitigate adverse reliability impacts of extreme weather events.”
No
R1.2.5: Duke Energy requests clarification on the intent of R1.2.5. Is it the intent of the SDT for a TOP to coordinate a Manual Load Shedding Plan to reduce the double counting of load used in an Automatic Load Shedding Scheme, or to reduce the overall dependency on the use of Automatic Load Shedding? A re-wording is needed to clearly state the purpose of this requirement. Also, we request further explanation as to what the SDT means by using the term “coordination” in the requirement. Further explanation as to what the SDT means by using “coordination” could provide some clarity on how a TOP can minimize the use of Automatic Load Shedding in favor of a Manual Load Shedding Plan. Duke Energy is of the opinion that the term “minimize” as used in the requirement is difficult to quantify, and is not a term equated with Auditability.
Yes
No
See Duke Energy comments on question 2. In addition we suggest the following rewording of R2.2, “Procedures, processes, or strategies to prepare for and mitigate Emergencies including a list for consideration, that addresses at a minimum:”
No
See Duke Energy comments on question 3.
Yes
No
Duke Energy suggests replacing “coordinate” with “review” in R3 as follows: “Each Reliability Coordinator shall review the Emergency Operating Plans of the entities in its Reliability

Coordinator Area to ensure that the plans are compatible and support reliability in the Reliability Coordinator Area." This provides consistency with the language in R5 of EOP-006-2 where an RC reviews the Restoration plans to determine if they are compatible and support the Reliability of the RC Area.
Yes
Yes
Yes
No
Duke Energy suggests the following revision to R7: "Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as practicable, neighboring Reliability Coordinators and those Balancing Authorities and Transmission Operators within its Reliability Coordinator Area." We believe this change is necessary because the use of the word "impacted" is broad and subject to interpretation by an auditor. However, the RC should be required to notify neighboring RCs who can notify those BAs and TOPs within its RC area for determination on the impacts the Emergency could have on their respective systems. By notifying the TOPs and BAs within its RC area, it provides the situational awareness necessary to protect the reliability of the BES.
No
Duke Energy believes the proposed language for R8 could be interpreted to mean that all the steps in the entity's Emergency Operating Plan have to be performed before requesting the RC to declare an EEA. Our belief is that the entity's plan should include the steps taken for each EEA level that leads up to the entity making a determination to declare an EEA by making a request to the RC. We propose the following language for R8: "R8. Each Balancing Authority shall request its Reliability Coordinator to declare the appropriate NERC Energy Emergency Alert level, according to the Balancing Authority's Emergency Operating Plan, when the Balancing Authority is unable to resolve the potential or actual capacity or Energy Emergency condition. " We believe the proposed modification clarifies that not all the steps in an entity's Emergency Operating Plan has to be performed before declaring and EEA.
Yes
No
See comments on 16. If the decision is made to move this to the NERC Glossary of Terms and a Guidance Document, Duke Energy will do a thorough review of Attachment 1 and provide necessary comments.
Yes
Duke Energy agrees with this approach for the following reason. By moving Attachment 1 to the NERC Glossary of Terms and adding a Guidance Document, it provides subsequent SDTs the flexibility to amend the EEA levels as necessary within one Standards Development

project without having to initiate multiple Standards Development projects simultaneously. This prevents the posting of projects for the sole purpose of modifying an Attachment to a Standard.
Yes
Duke Energy suggests replacing “requirements” with “obligations” in the definition of Energy Emergency. Our proposed definition is as follows: “Energy Emergency - A condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide its expected Load obligations.” We believe obligated is a more appropriate term because LSEs or BAs are not required to serve load, rather they are obligated to do so.
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
Yes
Yes
Southern requests clarification on the term “Emergency Operating Plan.” Did the SDT intend for “Emergency Operating Plan” to be a new term or is the meaning associated with each term separately: “Emergency” and “Operating Plan.” This standard reemphasizes a widespread concern that the definition of “Emergency” in the NERC Glossary is too broad to make it possible to create this document. We feel that an Emergency Operating Plan should exist for significant operating conditions and not the full spectrum of conditions that the current Emergency term encompasses.
No
Southern does not agree that R1, Part 1.2.5 clearly defines required performance. Southern recommends that the SDT modify the rationale included in the standard or the technical background and rationale document to clearly explain the intent of the requirement.
Yes
Other standards adequately cover the time frame requirements.
No
Southern does not believe all of the “minimum” set of elements outlined in R2.2 should be included for the BA. EOP-001-b R4 states, “Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan.” Southern also believes verbiage from the current version that states that only applicable requirements for an entity are to be included in a Plan should also be stated in this revised requirement. Some of the areas of concern in R2.2 are: • R2.2.2 and R2.2.3: What is the difference between Voluntary Load reductions and Public appeals? • R2.2.4: What governmental programs is the SDT referring to? • R2.2.6: What customer fuel switching? Why is this part of a minimum required set of Plan content since it is our experience that this is not

a widespread option for most entities? Southern recommends an additional requirement being added that requires the GOP to provide the data to the BA.
No
Southern does not agree that R2, Part 2.2.8 clearly defines required performance. Southern recommends that the SDT modify the rationale included in the standard or the technical background and rationale document to clearly explain the intent of the requirement.
Yes
Other standards adequately cover the time frame requirements.
No
Southern does not agree that the Reliability Coordinator should be obligated to review/approve all TOP and BA Emergency Operating Plans. This requirement/standard places an administrative burden on Reliability Coordinators to review / approve numerous Emergency Operating Plans. Historically, RC approval has not been required and registered TOPs/BAs have implemented their emergency plans to mitigate the emergencies without negatively impacting neighboring TOPs/BAs, so it is not clear why RC approval is now required. Southern requests the SDT reconsider RC approval. If the requirement remains: • The term “coordinate” should be changed to “review” because “coordinate” implies a more active involvement in the development of the Operating Plans, including such items as facilitating development meetings, etc. That would be required to merely review and approve/disapprove a Plan. • The SDT should more clearly, in the requirement itself or in the Rationale, describe what Plan parameters they feel should be evaluated for “compatibility” so that there will be consistency among the RC review activities.
Yes
If R3 remains, the 30 day review time is appropriate but that the 30 day time period should be prior to any implementation date specified in the BA/TOP Operating Plan. As was acknowledged by FERC in its Order for EOP-006, approval of these plans does not guarantee that they will adequately mitigate an Emergency for a BA/TOP but merely that the plans are compatible and support reliability. This concept needs to be captured in the requirement.
Yes
Yes
Yes
Southern would like to see more guidance on determining what “impacted” means since it can be a subjective term and therefore makes the requirement less measureable.
No
There is no progressive severity associated with the words in R8 that reflect the multiple levels of an energy emergency condition outlined in Attachment 1. As written R8 seems to indicate that an Energy Emergency Alert is not initiated until all steps of an Emergency Operating Plan are exhausted. Southern also believes that the SDT, either in the Requirement or Attachment, should take the opportunity to clarify that it is not necessary to explicitly call

for manual load shedding to return ACE to zero or to restore generation operating reserves under the new Energy Emergency Alert Level 4 unless to not do so creates a risk to the Interconnection.
Yes
No
Southern prefers the previous three levels in the current Attachment 1 and sees only minimum advantages to the addition of the fourth level. Southern does believe that some of the clarifications in the new Attachment of the existing wording is an improvement. If the SDT chooses to keep the 4 levels then we have the following comments: • Alert Level 2 refers to "available resources" – Does that include demand side resources or just generation? • Does the SDT believe that demand side options are prohibited from being used unless an Alert Level 3 is declared? This needs to be clarified based on the heading of Alert Level 3. • Item 3.5.3 refers to Emergency Assistance through an operating reserve sharing program. Not all BAs have Operating Reserve Sharing programs and not all emergency assistance is obtained through operating reserve sharing programs. The new EOP-011 has lost the concept of BAs requesting emergency assistance directly from other Bas without the use of a reserve Sharing Agreement. Seeking emergency assistance through RC coordination efforts needs to be emphasized since it often may be the primary mechanism for restoring reserves and avoiding manual load shed.
No
The SDT needs to provide additional guidance on the compliance implications of leaving it as an Attachment or implementing the proposal of the Attachment being incorporated into the NERC Glossary of defined terms. For example, does an Attachment to a standard imply any more compliance obligation than the same words in a guidance document?
No
Individual
David Thorne
Pepco Holding Inc.
Yes
No
Why not include many of the other elements included in R2 for Transmision Emergencies?
Yes
Yes
Don't need to duplicate the same requirement in different Standards.
Yes

Yes
Yes
Don’t need to duplicate the same requirement in different Standards.
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Group
SERC OC Review Group
Stuart Goza
Yes
The OC Review Group supports the EOP SDT action to combine three standards into the proposed EOP-011-1. Further, the OC Review Group thanks the EOP SDT for their efforts in developing the proposed EOP-011-1.
No
The OC Review Group is concerned with the phrase “At a minimum” as it is possible that certain elements may not be applicable to a certain TOP. It is recommended that the term “applicable” be utilized. Current R1 language: R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency

Operating Plan shall include the following elements: Proposed R1 language: R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. The Emergency Operating Plan shall include the applicable elements when developing an Emergency Operating Plan:
No
The OC Review Group recommends that adding “Operator controlled” further clarifies R1, Part 1.2.5 R1, Part 1.2.5. Current language: Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; R1, Part 1.2.5 Proposed language: Operator controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding;
Yes
No
The OC Review Group is concerned with the phrase “At a minimum” as it is possible that certain elements may not be applicable to a certain TOP. It is recommended that the term “applicable” be utilized. Current R2 language: Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: Proposed R2 language: Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. The Emergency Operating Plan shall include the applicable elements when developing its Emergency Operating Plan:
No
The OC Review Group recommends that adding “Operator controlled” further clarifies R2, Part 2.2.8 Current language: 2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; Proposed language: Operator controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding;
Yes
The SERC OC Review Group respectfully recommends that the SDT consider changing M2 to align with M1 by identifying the Reliability Coordinator as the approving entity. Current M2 language: Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R2. Proposed M2 language: Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2 that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability Coordinator; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R2.
Yes

Yes
Yes
Yes
No
The SERC OC Regroup respectfully requests further guidance and clarification on the term “impacted”. The concern centers on which entities would be considered “impacted”. Current R7 language: Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as practicable, impacted Reliability Coordinators, Balancing Authorities and Transmission Operators.
No
The SERC OC Review Group recommends two changes to R8. The first is to add the term “appropriate” to the requirement and the second recommendation is to move R8 to R2 as a new Part 2.4 and eliminate R8. Current R8 language: The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert after the Balancing Authority has performed the steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. Proposed R8 language: The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert after the Balancing Authority has performed the appropriate steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. Proposed R8 language moved to a new R2, new Part 2.4: The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert after the Balancing Authority has performed the appropriate steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. This move to R2, new Part 2.4 will permit deleting R8. If the SDT accepts the R8 change then M8 will also require inserting the term “appropriate” into the measure to be consistent with R8. Current R8 language: Each Balancing Authority who, after performing the steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition, will have and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that it requested its Reliability Coordinator to declare a NERC Energy Emergency Alert in accordance with Requirement R8. Propose M8 language: Each Balancing Authority who, after performing the appropriate steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition, will have and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that it requested its Reliability Coordinator to declare a NERC Energy Emergency Alert in accordance with Requirement R8. If the EOP SDT accepts moving R8 to a new R2, Part 2.4 then the team recommends the following to the M2: Current M2 language: Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2; and will have as evidence,

such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R2. Proposed M2 language: Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2. In the case where each Balancing Authority who, after performing the appropriate steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition, will have and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that it requested its Reliability Coordinator to declare a NERC Energy Emergency Alert in accordance with Requirement R8.
Yes
No
The SERC OC Review Team requests clarification on 1. Alert 1 — Forecast the need for an Energy Emergency. Circumstances: • Energy Deficient Entity foresees the need to issue alerts in the upcoming operating window and is concerned about Operating Reserves. The specific concern centers on what is meant by the phrase “upcoming operating window”. As written each entity could select a different “upcoming operating window”.
No
The OC Review Group request further clarification on R1 and R2 minimum set of elements. There are cases where specific elements may be utilized for non-emergency reasons. For example, voltage reduction, load curtailable load and interruptible load can be utilized for non-emergency purposes. Would these activities constitute plan implementation? C. 1.1.2 Evidence Retention: If the EOP SDT accepts deleting R8 and creating a new R2, Part 2.4 then the evidence retention section would require modification. Current language: The Balancing Authority shall maintain evidence of compliance since the last audit for Requirements R6 and R8 and Measures M6 and M8. Proposed language: The Balancing Authority shall maintain evidence of compliance since the last audit for Requirements R2 and R6 and Measures M2 and M6. The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Group
ACES Standards Collaborators
Ben Engelby
Yes
We support the consolidation of the three standards, but we question why the drafting team chose to label the new standard as EOP-011-1. Why wouldn’t the revised standard be labeled as EOP-001-3? This would be consistent with other drafting team projects and would be less confusing to industry members that do not follow the standards development process that

closely. Considering this EOP standard is going to consolidate the key emergency operations standards, it only makes sense to call it EOP-001.
No
(1) We see several issues with these proposed requirements. First, the term “Emergency Operations Plan” is not a defined term. This should either be lowercase or the SDT should propose to add it to the NERC glossary. (2) The glossary term “Energy Emergency” is not the same as “Energy Emergency Alert.” The supplemental document showing each standard that uses the term has incorrectly identified an EEA. We recommend reviewing the standards again to verify that the revision to the glossary term does not impact standards that use the word “emergency” in the requirements. (3) The RC approval process is an administrative action that does not support reliability. The approval process should be completed internally. This process is a burden for RCs and registered entities, especially smaller entities that may not have an impact on the reliability of the RC Area. Having an internal approval that aligns with the RC emergency plans would satisfy the intent of the requirement, but would also limit the administrative functions that relate to getting an approval from the RC. The requirement could state that the plans must align with RC emergency plans, which are posted and available to all registered entities in the RC Area. Verifying this information is much simpler if done internally, instead of burdening RC staff with approving each member’s plan. As an alternative, the RC could be required to simply review the plans for conflicts. (4) Does the RC need to approve every change to the plan? Within what timeframe? The standard is not clear regarding the process for getting RC approval and secondary approvals for subsequent changes. Again, this is administrative in nature. (5) Requirement R1, part 1.3, meets Paragraph 81 criteria because it is completely administrative. There is no reason that a standard needs to require the details of a revision process. The requirement already has the word “maintain” in relation to the plan, which implies that updates will be made when necessary. This should be removed.
No
(1) It is not clear what parties are supposed to coordinate their plans. Coordination is an ambiguous term that could be interpreted in multiple ways. The measure does not provide any additional guidance on what is expected for coordination and the drafting team did not provide compliance guidance or an RSAW with this draft. Are TOPs supposed to coordinate with other TOPs? Other BAs? Or is the standard proposing that the RC approval process is evidence of coordination? This is not clear and needs to be revised. The bottom line is that coordination is a vague requirement that needs to be further refined to clearly spell out what is required for coordination.
Yes
We support manual firm load shedding without a specific time measure. However, we are concerned the compliance monitoring approaches may create a de facto time requirement. We would like to see guidance or an RSAW to state how this will be evaluated.
No
(1) As stated in early comments, we do not support the RC approval process because it is primarily an administrative function. (2) Has the drafting team considered the situation where

an entity may have load in two different RC Areas? Would they need to have two separate plans and two separate approvals from each RC? What happens if there are three RCs? There are several entities in North America that operate in several regions. This standard is proposing a highly complicated approval process that is unnecessary for reliability.
No
(1) We would like clarification on minimizing the use of automatic load shedding. Manual load shedding could be an operator pushing a button to initiate load shedding. We believe the standard is attempting to state that manual load shedding should be planned to minimize the use of UFLS or UVLS. However, the standard is not this specific and needs to be clarified. (2) We are concerned about the ambiguous term of coordination and the varying compliance monitoring approaches from regional entities. We would like to see compliance guidance or an RSAW to state how this will be evaluated.
No
(1) We support manual firm load shedding without a specific time measure. However, we are concerned about the ambiguous term of coordination and the varying compliance monitoring approaches from regional entities. We would like to see compliance guidance or an RSAW to state how this will be evaluated. (2) Part 2.2.9 needs to be revised. The clause “if not covered by other elements of the plan” is confusing and does not need to be in a requirement. Either the BA needs to have a strategy for extreme weather or not. This language only adds confusion and needs to be removed.
No
Why not require the RC to post its emergency operating plans and notify all of the entities in its area of any changes? The TOP and BA could align their emergency plans with the RC and then the RC could review these plans for conflicts. The RC already is required to perform emergency operations training with other entities, so requiring an approval process is administrative and unnecessary.
No
(1) Does the drafting team really think that 30 days is sufficient amount of time to review potentially dozens of plans? What if they were all submitted during peak season? What is more important to reliability – reviewing documentation or the actual operation of the Bulk Electric System? The timeframes are administrative in nature and a burden on all entities that would have to comply. We strongly urge the drafting team to consider a different approach.
No
We do not support the requirement as written. Why can’t this notification requirement be included in the emergency operating specified in R1? This would eliminate the need for this requirement.
No
We do not support the requirement as written. Why can’t this notification requirement be included in the emergency operating specified in R2? This would eliminate the need for this requirement.
No

We request that the drafting team remove the language “as soon as practicable” from R7. This is ambiguous language, which cannot be measured and will only lead to confusion. We suggest replacing this clause with the word “other,” so the requirement will state “…notify other impacted RCs, BAs, and TOPs.” Otherwise, the requirement will literally require the RC to also notify the BA or TOP that just notified it.
No
The Emergency Operating Plan should not have to be exhausted to notify the RC of an EEA. Part of the Emergency Operating Plan should be when to notify other entities that will be impacted, including when to request an EEA from the RC. It is better for reliability to have the BA communicating with the RC if the BA anticipates a deficiency, rather than requiring the BA to exhaust all steps first. Furthermore, this requirement actually conflicts with the requirements to have Emergency Operating Plans in R1 and R2 because it requires these Emergency Operating Plans to be fully implemented. This would include manual load shedding in Part 2.2.8. Per the requirements in Attachment 1, an EEA3 should be issued when load management has been issued but it can’t without violating R8 because the Emergency Operating Plan steps have not been fully exhausted. We recommend removing R8 from the standard and incorporating the notification into R1 and R2.
Yes
We thank the drafting team for clarifying that the Load Serving Entity is not applicable. We would like to see this language in an RSAW.
Yes
Adding an additional alert level to the attachment is confusing, especially when Alert 4 requires the entity to continue actions it was doing in Alert 3. We strongly suggest revising this document to have bright line differences between each alert level. Was there a reliability need to modify the prior attachment? Were a majority of registered entities having issues with the concepts of the EEA process?
Yes
We could support the removal of attachment one, as long as the alert levels remain the same (zero through 3). If the drafting team is going to revise the alert levels as proposed in the current draft by including alert level 4, then it would be better to keep the attachment with the standard.
Yes
(1) The VSL table is blank. We cannot support a standard that is incomplete and does not provide guidance on how enforcement will be interpreting this standard and translating violations into monetary penalties. (2) The guidelines and technical basis section is blank. We suggest waiting to post draft standards until they are complete. (3) Thank you for the opportunity to comment.
Group
DTE Electric
Kathleen Black

Yes
Yes
Yes
Yes
No
• The end of the first sentence “capacity and Energy Emergencies” should be “Capacity and Energy Emergencies” since Capacity Emergency and Energy Emergency are both defined terms in the NERC Glossary. • EOP-001-2.1b Attachment 1 listed “Elements for Consideration in Development of Emergency Plans”. Since the BA only had to consider the elements, those that were not applicable did not need to be addressed in the plan. As written, EOP-011 R2 requires the BA to develop procedures, processes or strategies for items that would not apply to their BA area. Consider replacing “At a minimum, the Emergency Operating Plan shall include:” with “As applicable to the Balancing Authority, the Emergency Operating Plan shall include:”. To show compliance, the BA would respond in the RSAW that certain elements were considered but not applicable. • This comment is complementary to the suggestion in comment 13 below regarding EEA levels. Consider adding 2.2.10: “The appropriate conditions under which NERC Energy Emergency Alerts are to be requested.”
Yes
Yes
Yes
Yes
Yes
No
• The end of the first sentence “capacity or Energy Emergencies” should be “Capacity or Energy Emergencies” since Capacity Emergency and Energy Emergency are both defined terms in the NERC Glossary.
Yes
No

• Requesting the RC to declare a NERC EEA should be an integral part of a BA’s plan. As written, “..after the Balancing Authority has performed the steps in its Emergency Operating Plan…” implies the entire BA plan has to be executed prior to requesting an EEA level. This can be interpreted as the BA must get all the way to manual load shed before requesting “Alert 1 — Forecast the need for an Energy Emergency”. • This comment is complementary to the suggestion in comment 5 regarding inclusion of EEA levels in the Emergency Operating Plan. Suggest rewriting R8 as follows: “The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert when conditions warrant in accordance with the Balancing Authority's Emergency Operating Plan.”
Yes
No
• In the second line of the Introduction of section B, change “NERC has established three levels…” to “NERC has established four levels…” • Alert 1: The purpose of Alert 1 is an Energy Deficient Entity is projecting to move into Alert 2, 3, or 4. Operating Reserves are addressed in Alert 2 and 3 so do not need to be mentioned in Alert 1. Consider changing Alert 1 Circumstances to the following: “Energy Deficient Entity foresees the need to request the Reliability Coordinator issue Alerts 2, 3, or 4 in the upcoming operating window.” • Alert 3 Circumstances: The second bullet has vague language “…implemented its approved Emergency Operations Plan”, it does not specify what steps have been implemented. Since alert 3 is supposed to address “Load management procedures in effect”, consider adding examples of Load management to this bullet. NERC EOP-002-3.1 alert 2 bulleted list adequately describes Load management: o Public appeals to reduce demand. o Voltage reduction. o Interruption of non-firm end use loads in accordance with applicable contracts o Demand-side management. o Utility load conservation measures.
No
Suggest leaving the content in Attachment 1. Moving EEA levels to the glossary and a separate guidance document will unnecessarily complicate the language of R9. As written, R9 is clear and concise.
No
Group
Tennessee Valley Authority
Dennis Chastain
Agree
SERC OC Review Group
Individual
Scott Langston
City of Tallahassee

Yes
No
The language from R1.2.6 referring to the potential impacts of extreme weather is difficult to quantify. Due to the lack of specificity, TAL would create “high level strategies” similar to those created for restoration from black start resources. Also, requiring the RC to approve the plan places an administrative burden on both the entity and the RC.
No
- TAL is confused by R1.2.5. Is the intent not to overlap manual and automatic (UFLS) load shed tools (i.e. feeder circuits) or is the intent to require manual load shedding prior to activation of automatic load shedding? - The verbiage does not specify who must be part of the coordination effort.
Yes
No
TAL does not understand the intent of R2.2.4 (Governmental programs) in an emergency context. As written, it appears the language suggests entities plan for emergencies with an expectation of assistance from government programs. It is our belief that our plan should accommodate the worst case scenario. Also, requiring the RC to approve the plan places an administrative burden on both the entity and the RC.
No
TAL is confused by R2.2.8. Is the intent not to overlap manual and automatic (UFLS) load shed tools (i.e. feeder circuits) or is the intent to require manual load shedding prior to activation of automatic load shedding? The verbiage does not specify who must be part of the coordination effort.
Yes
Yes
No
- Requiring RC approval will add an administrative burden on each side. - If approval is the end result, TAL recommends combining R4 with R3 to make one requirement requiring coordination and approval or disapproval. - Recommend 60 days for approval. Although the submittal is on an approved schedule the “RC” is not a single person, but rather a committee. Work products often need to go through a formal committee process to gain “approval”. 60 days minimizes the burden.
Yes

Yes
While TAL supports the proposed requirement, we maintain that more clarity is needed regarding “the steps in its Emergency Operating Plan”. TAL recommends changing the language to include “appropriate steps” or “necessary steps”. It is not necessary for all steps in the plan be completed prior to requesting an EEA. This should be allowed.
Yes
Yes
Yes
No
Individual
Bill Fowler
City of Tallahassee, TAL
Yes
No
The language from R1.2.6 referring to the potential impacts of extreme weather is difficult to quantify. Due to the lack of specificity, TAL would create “high level strategies” similar to those created for restoration from black start resources. Also, requiring the RC to approve the plan places an administrative burden on both the entity and the RC.
No
TAL is confused by R1.2.5. Is the intent not to overlap manual and automatic (UFLS) load shed tools (i.e. feeder circuits) or is the intent to require manual load shedding prior to activation of automatic load shedding? The verbiage does not specify who must be part of the coordination effort.
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No

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Yes
Yes
No
-Requiring RC approval will add an administrative burden on each side. -If approval is the end result, TAL recommends combining R4 with R3 to make one requirement requiring coordination and approval or disapproval. -Recommend 60 days for approval. Although the submittal is on an approved schedule the "RC" is not a single person, but rather a committee. Work products often need to go through a formal committee process to gain "approval". 60 days minimizes the burden.
Yes
Yes
Yes
Yes
While TAL supports the proposed requirement, we maintain that more clarity is needed regarding "the steps in its Emergency Operating Plan". TAL recommends changing the language to include "appropriate steps" or "necessary steps". It is not necessary for all steps in the plan be completed prior to requesting an EEA. This should be allowed.
Yes
Yes
Yes
No
Individual
Karen Webb
City of Tallahassee
Yes

No
The language from R1.2.6 referring to the potential impacts of extreme weather is difficult to quantify. Due to the lack of specificity, TAL would create “high level strategies” similar to those created for restoration from black start resources. Also, requiring the RC to approve the plan places an administrative burden on both the entity and the RC.
No
TAL is confused by R1.2.5. Is the intent not to overlap manual and automatic (UFLS) load shed tools (i.e. feeder circuits) or is the intent to require manual load shedding prior to activation of automatic load shedding? The verbiage does not specify who must be part of the coordination effort.
Yes
No
TAL does not understand the intent of R2.2.4 (Governmental programs) in an emergency context. As written, it appears the language suggests entities plan for emergencies with an expectation of assistance from government programs. It is our belief that our plan should accommodate the worst case scenario. Also, requiring the RC to approve the plan places an administrative burden on both the entity and the RC.
No
TAL is confused by R2.2.8. Is the intent not to overlap manual and automatic (UFLS) load shed tools (i.e. feeder circuits) or is the intent to require manual load shedding prior to activation of automatic load shedding? The verbiage does not specify who must be part of the coordination effort.
Yes
Yes
No
Requiring RC approval will add an administrative burden on each side. If approval is the end result, TAL recommends combining R4 with R3 to make one requirement requiring coordination and approval or disapproval. Recommend 60 days for approval. Although the submittal is on an approved schedule the “RC” is not a single person, but rather a committee. Work products often need to go through a formal committee process to gain “approval”. 60 days minimizes the burden.
Yes
Yes
Yes

Yes
While TAL supports the proposed requirement, we maintain that more clarity is needed regarding “the steps in its Emergency Operating Plan”. TAL recommends changing the language to include “appropriate steps” or “necessary steps”. It is not necessary for all steps in the plan be completed prior to requesting an EEA. This should be allowed.
Yes
Yes
Yes
No
Individual
William Temple
Northeast Utilities
Yes
Yes
Yes
We agree with the need to coordinate manual load shedding with other load shedding actions, but Part 1.2.5 appears to fall a bit short of with whom or with which plans a TOP needs to coordinate its manual load shedding plan. We suggest expanding this part as follows: 1.2.5 Manual Load shedding plan coordinated with automatic loading programs to minimize the use of automatic Load shedding, and also coordinated with the manual load shedding plans of other entities in the Reliability Coordinator Area to avoid insufficient or excessive manual load shedding.
Yes
Yes
Yes

Yes
Yes
Global Comment: “Emergency Operating Plan” is capitalized but it is not a defined term in the glossary of terms and there is no definition included in this draft of the standard. A definition should be added or it should not be capitalized. Comment on R1 and R5: the standards talk about “operating Emergencies.” There are definitions for “Energy Emergency,” “Capacity Emergency,” and “Emergency” (or “BES Emergency”). If the definition of “Emergency” captures what is needed, then the word “operating” should be deleted. The phrase “operating Emergency” also appears in R5. Comment on R2, R6, and R8: Energy Emergency has a definition in the draft – but “capacity” is not capitalized in “capacity Emergency.” The definition of “Capacity Emergency” in the Glossary is “[a] capacity emergency exists when a Balancing Authority Area’s operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.” So, if this is what the standard means by “capacity Emergency,” then it should be capitalized. R2 should read: “to mitigate Capacity Emergencies and Energy Emergencies.” Same issue in R6 and R8.
Group
ISO/RTO Standards Review Committee
Greg Campoli
Yes
Yes
Yes
We agree with the need to coordinate manual load shedding with other load shedding actions, but Part 1.2.5 appears to fall a bit short of with whom or with which plans a TOP needs to coordinate its manual load shedding plan. We suggest expanding this part, and add a new part as follows: 1.2.5 Manual Load shedding plan coordinated with automatic load shedding programs to minimize the use of automatic Load shedding; 1.2.6 Manual Load shedding plan coordinated with the manual load shedding plans of other entities in the Reliability Coordinator Area to avoid insufficient or excessive manual load shedding;
Yes
We agree with not specifying a time frame since the time required to implement and complete manual load shedding will depend on a number of conditions, such as: the

completion of the automatic load shedding and its effects on mitigation, the time needed for manual load shedding to be completed from the time of initiation, other available actions that may be taken prior to shedding load, etc. The reliability driver is to arrest/mitigate an Emergency as soon as possible. System Operators will have this reliability driver in mind when faced with an Emergency, and are the best judges of when manual load shedding should be initiated and completed.
No
We agree with the general intent of R2, but have the following comments: R2.2 requires the BA to develop procedures, processes or strategies to prepare for and mitigate emergencies. Thus, the actionable obligations under 2.2 are the development of procedures. Requirements 2.2.1-2.2.9 are intended to establish a non-exclusive list of means to address the emergencies for which the entity is to have related procedures/plans/strategies. With respect to R2.2.2-R2.2.9, the standard achieves its goal, because those requirements list ways / means to address the emergency, and then 2.2 requires the entity to have plans to utilize those means to mitigate the emergency. However, R2.2.1 does not accomplish this goal, because, as written it does not establish a means of addressing the emergency. Rather, it simply identifies characteristics of generating units. In order to make sense under the standard, R2.2.1 needs to be revised to make it clear that the entity is to apply generating unit characteristics in some context for use in mitigating an emergency. For example, it could be revised as follows (add highlighted language): 2.2.1. Appropriate utilization of generating resources in its Balancing Authority Area taking into consideration all relevant until characteristics, including, but not limited to, the following: 2.2.1.1. capability and availability; 2.2.1.2. fuel supply and inventory concerns; 2.2.1.3. fuel switching capabilities; 2.2.1.4. environmental constraints. In addition to the above context comment, we recommend the SDT discuss how this standard can be practically implemented, and consider whether the standard can actually achieve some of the underlying objectives. First, there are terms such as “extreme weather” and “coordinate” that are commonly used in the industry – but may not be precise enough in a mandatory requirement associated with compliance. There is no defined term of what extreme weather is and what may be considered extreme in one geographic location may not be extreme in another. For example, one would not expect a large metropolitan area in the South, to have a massive fleet of ice and snow removal equipment on stand-by to clear roads for a 1 in 100 year ice/snow storm. Such should also be considered for the electric industry. The SDT should have a clear way to communicate their expectations to the entities impacted by this standard on how to interpret for them what is an appropriate extreme event. In addition, there are numerous instances where entities are required to coordinate with other entities on emergency plans. However, there is no explanation of what constitutes appropriate coordination. Without guidance on how entities must coordinate, it will be difficult for entities to know the nature and degree of coordination necessary to meet such requirements. Lastly, there should not be an expectation that Transmission Operators, Balancing Authority and Reliability Coordinators will have authority over a Generator Operator’s decisions to reserve its fuel supplies to meet plans developed by the Balancing Authority in advance of any potential emergency conditions. Generators make economic decisions on what and how much fuel to burn. We do not interpret this standard as having any mandatory requirement

for any entity to determine when they will or will not run their units to preserve any particular fuel source. On the other hand, if the expectation is that a BA needs to have an Emergency Operating Plan to mitigate resource constraints under insufficient fuel supply situation, then the only option is rotational load shedding during a prolonged period of fuel supply deficiency after all other measures have been exhausted. a. The intent of and linkage between R2, Part 2.2, its sub-parts 2.2.1 and those parts listed under 2.2.1 are unclear. The last sentence in R2 says: “At a minimum, the Emergency Operating Plan shall include: 2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum: 2.2.1 Generating resources in its Balancing Authority Area 2.2.1.1 Capacity and availability It is unclear on what’s expected from 2.2 when it asks for procedures, etc. to prepare for and mitigate Emergencies, then 2.2.1 starts off by saying “Generating resources…” Does it mean having procedures, etc. to mitigate Emergencies caused by generating resource deficiency? The whole R2 and its parts need to be worded to provide clarity. b. All the parts under Part 2.2.1 are unclear as to what it is that the BA is supposed to guard against. For example, is the BA supposed to prevent the generating resource shortage caused by fuel supply and inventory concern (Part 2.2.1.2) or by environmental constraints (Part 2.2.1.4)? Under these conditions, we are unable to see how a BA can hope to have Emergency plans or procedures in place to mitigate prolonged resource shortage caused by these events, some of which are unpredictable and whose mitigation can be out of a BA’s capability and control. If a BA is unable to mitigate the adverse impact, shedding firm load may well be the last resort. The standard needs to have this provision to ensure the BA does not become liable for events that it did not cause or over which it had any control.
No
Same comments on R1.2.5 under Q3 on the need to expand this part to more clearly stipulate with whom or which plans a BA needs to coordinate its manual load shedding plan.
Yes
Same comment for Part 1.2.5 under Q4, above.
Yes
We support the proposed requirement, and we agree with the intent of R3 and R4 (i.e., to have Emergency Operating Plans by the TOPs and BAs coordinated, and approved by the RC). However, we believe that putting the coordination responsibility solely on the RC (as Requirement R3 so suggests) is neither sufficient nor appropriate. The TOPs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other TOPs and BAs in the RC Area. Likewise, the BAs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other BAs and TOPs in the RC Area. The RC’s role, then, will be to assess if such coordination occurred, and approve or disapprove the EOPs. We suggest R3 be revised to explicitly state the responsibilities for the TOPs and the BAs (or any other entities within the RC’s Area) to coordinate their EOPs. Alternatively, a new requirement may be created to capture such responsibilities.
Yes

We agree with the proposed R4, assuming that coordination between TOPs and BAs has occurred prior to the submittal of the individual EOPs. Please refer to our comments/suggestions under Q8, above.
Yes
We support the addition of R5 to have a Transmission Operator that is experiencing an Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. We are indifferent as to who should be responsible for communicating the Emergency to other TOPs and/or BAs that may be impacted by it, as long as this is performed by a responsible entity.
Yes
We are indifferent as to who should be responsible for communicating the capacity Emergency or Energy Emergency to other TOPs and/or BAs that may be impacted by the TOP's capacity or Energy Emergency, as long as this is performed by a responsible entity.
Yes
We are indifferent as to who should be responsible for providing notification of an Emergency from a TOP or BA within a RC Area to those entities that are impacted or could be impacted, as long as this is performed by a responsible entity. In deciding who should be responsible, the SDT should consider that, while holding the RC responsible for this notification is more streamlined and coordinated, it requires additional time to complete the notification. On the other hand, holding the individual entity whose area is experiencing an Emergency responsible for such notifications can speed up information dissemination, but may lack information that could have been included in a report provided by an RC, with its oversight and wider-area view.
Yes
Yes
No
While the initial Attachment 1 is largely intact, we notice that the notification details under an Alert 2 have been removed. The mapping document does not provide the rationale for the removal, nor is it presented in any of the technical justification documents. While we believe that there is a need to keep such details in the revised Attachment 1, we have not been provided the basis of the removal to aid an assessment. Please provide the rationale.
No
While we could support defining the EEA levels through a definition, and incorporating them into the NERC Glossary, Attachment 1 also serves the purpose of providing necessary information associated with and required for issuing EEAs. Including part of that information into the Glossary of Terms will make the defined term very lengthy. In addition, moving other information to a guideline document is only possible if the information currently included in Attachment 1 is not mandatory. Unfortunately, we cannot locate the detailed technical justification the EOP SDT used to support the proposed removal of all information in

Attachment 1 that are “requirements.” Please provide it with the next posting so that we can assess the merit of this proposal. A mapping of the detailed information in Attachment 1 after the proposed removal will be very helpful. While we do not support defining EEA levels as proposed, we do have the following comments regarding the proposed definition for Energy Emergency and suggestion for defining the three terms and adding them to the NERC Glossary as appropriate: In the revised definition of Energy Emergency the word “energy" has been replaced with "Load". The revised definition now seems to imply that reserves have been exhausted and a BA simply can't serve load. On the other hand, the word “energy” implies that planned dispatch has been used up and a BA must now begin to utilize reserves, which we believe is more aligned with the EEA steps. We suggest restoring the word “energy”. Further, we suggest replacing “provide” with “meet”. The revised definition will thus read: Energy Emergency - A condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer meet its customers’ expected energy requirements. We propose to define the following three terms: “Energy Emergency Alert” “Energy Deficient Entity” “Emergency Operating Plans” The term Energy Emergency Alert is referenced in the standard and in Attachment 1, and is capitalized. But this term is not defined in the NERC Glossary. Similarly, the term Energy Deficient Entity is referenced in Attachment 1 and is capitalized, but it is not defined in the NERC Glossary. Likewise, the term Emergency Operating Plan is referenced in the standard and is capitalized, but it is not defined in the NERC Glossary. These terms need to be put in lower case, or defined for use in this standard only, or defined and included in the Glossary. Additional comment on Attachment 1, Alert 3 and Alert 0: the language here should match the language used in the revised definition of “Energy Emergency” (including our proposed edits) so as to say “can no longer meet its expected energy Load.” (Same comment under “Alert 0”).
Yes
Requirement R8 requires a BA to request its RC to declare EEA when necessary. R9 requires the RC to initiate an EEA when its BA or LSE is experiencing a potential or actual Energy Emergency. It implies that a RC needs to be watching the conditions in its area, and initiate the EEA as needed. However, such a process could also be initiated by a BA’s request under R8. If R9 is retained as written, then R8 could be removed, and a new requirement be added to require the RC to monitor the energy conditions in its area to detect potential or actual Energy Emergency of its BAs and LSEs. If R8 is retained, then we suggest that a new requirement be added to require the RC to monitor the energy situation as indicated above, plus revise R9 as follows: R9. Each Reliability Coordinator that receives notification from a Balancing Authority that is is unable to resolve a capacity or Energy Emergency condition or that assesses that a Balancing Authority or Load-Serving Entity is experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate a NERC Energy Emergency Alert, as detailed in Attachment 1. Comments on BAL-002-WECC-2 – Contingency Reserve: We are unclear on the inclusion of “BAL-002-WECC-2 – Contingency Reserve” and Requirement R1 on P. 3, Definitions of Terms Used in Standard. Please clarify. Also, “energy emergency” is not capitalized in one of the R1.1 bullets here – it should be because it is a defined term. Global Comment: “Emergency Operating Plan” is capitalized but it is not a defined term in the Glossary of Terms and there is no definition included in this draft of the

standard. A definition should be added or it should not be capitalized. Comment on R1 and R5: the standards talk about “operating Emergencies.” There are definitions for “Energy Emergency,” “Capacity Emergency,” and “Emergency” (or “BES Emergency”). If the definition of “Emergency” captures what is needed, then the word “operating” should be deleted. The phrase “operating Emergency” also appears in R5. Comment on R2, R6, and R8: Energy Emergency has a definition in the draft – but “capacity” is not capitalized in “capacity Emergency.” The definition of “Capacity Emergency” in the Glossary is “[a] capacity emergency exists when a Balancing Authority Area’s operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.” So, if this is what the standard means by “capacity Emergency,” then it should be capitalized. R2 should read: “to mitigate Capacity Emergencies and Energy Emergencies.” Same issue in R6 and R8.
Individual
Kayleigh Wilkerson
Lincoln Electric System
Yes
Yes
No
Recommend additional clarification be added to Part 1.2.5 to specify whether the loads used by the operators in a Manual Load Shedding plan are either used last, or not at all, in comparison to the loads that are already defined in any automatic under-frequency or automatic under-voltage load shed plans.
Yes
Yes
No
Refer to comment in Question #3.
Yes
Yes
Yes
Yes

Yes
Yes
Yes
Yes
No
Recommend the Energy Emergency Alert levels remain within the document where they are used.
Yes
While appreciative of the drafting team’s efforts in consolidating the Emergency Operations standards, LES believes the following areas may benefit from additional clarification. R9 – Although the Load Serving Entity (LSE) is no longer referenced as an applicable entity within EOP-011-1, the references to the LSE in R9 and Attachment 1 seem to imply that there is still the expectation that the LSE retains compliance responsibilities in case of a potential or actual Energy Emergency. As an example, in Attachment 1 Section B the “Energy Deficient Entity”, which is defined as an LSE or BA in the Attachment 1 Introduction, is required to “communicate its needs to other Balancing Authorities and market participants” (Part 3.1), in addition to updating the RC of the situation “at a minimum of every hour” (Part 3.2). To ensure entities are aware of their respective obligations, recommend either including the LSE as an applicable functional entity within EOP-011-1 or else modifying R9 and Attachment 1 to remove specific references to the LSE. R1, R2 – Per R1 and R2, the Transmission Operator and Balancing Authority are required to develop, maintain and implement an Emergency Operating Plan approved by the Reliability Coordinator. Is the drafting team’s expectation that the process entities establish in R1.3 and R2.3 will take the place of a minimum review requirement? As an example, rather than require entities to review their Plan annually as part of EOP-011-1, all reviews would be accounted for as part of the entity’s revision process developed in R1.3 and R2.3.
Group
Florida Power & Light
Mike O'Neil
Yes
No
This new requirement is too prescriptive, specifically requirement 1.2 where it defines minimum requirements a BA should include in the Emergency Operating Plan. Some of these requirements may not apply to all BAs.

No
Requirement not clear. Is this requirement intended to use the manual load shed to prevent automatic load shed; or is it to ensure that the same resource is not used for manual and automatic load shed.
Yes
No
This new requirement is too prescriptive, specifically requirement 2.2 where it defines minimum requirements a BA should include in the Emergency Operating Plan. Some of these requirements may not apply to all BAs.
No
Requirement not clear. Is this requirement intended to use the manual load shed to prevent automatic load shed or is it to ensure that the same resource is not used for manual and automatic load shed?
Yes
Yes
Yes
Yes
Yes
Yes
Yes
Yes
No
Current attachment 1 is adequate and adding an additional alert does not add value as forecasted conditions are covered under the existing attachment.
No
Current Attachment 1 provides the details needed to meet the requirements.
No
Individual

Joshua Smith
Oncor Electric Delivery Company LLC
Yes
Yes
Yes
Yes
Yes
Yes
Oncor Electric Delivery (Oncor) supports the revisions to Attachment 1 in the proposed EOP-011-1; however, Oncor cautions the separation of Energy Emergency Alert (EEA) 2 into two separate EEAs (2 and 3) since it would require a great deal of administrative revision and could limit flexibility to existing Procedures for all entities involved, with no reliability benefit from the separation. Oncor appreciates another look at this revision by the SDT. Additionally, for clarifying purposes, Oncor recommends that Responsibility 3.4 under Alert 3 in Attachment 1 should include the following changes: 3.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator should review Transmission outages and work with the Transmission Operator to see if it’s possible to return the Transmission element <back to service> that may <return the system to pre-emergency conditions or> relieve the Loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).
No
Oncor prefers and supports the use of the revised Attachment 1 in proposed EOP-011-1, with the changes suggested in Question 15.

Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
No
Requirement 3 requires the RC to coordinate the relevant plans to “ensure that the plans are compatible and support reliability in the Reliability Coordinator Area.” The RC review cannot “ensure” reliability. Furthermore, reliability is undefined, and, therefore ambiguous in this context. The wording should be revised as follows (consistent with EOP-006-2 R5) to mitigate these issues: R3. Each Reliability Coordinator shall review the Emergency Operating Plans required by EOP-011 of the entities within its Reliability Coordinator Area. [Violation Risk Factor = Medium] [Time Horizon = Operations Planning] R3.1. The Reliability Coordinator shall determine whether the entity’s Emergency Operating Plan is coordinated and compatible with the Reliability Coordinator’s Emergency Operating Plan and other entity’s within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with stated reasons, entity’s Emergency Operating Plan within 30 calendar days following the receipt of the entity’s Emergency Operating Plan. In addition to the RC, TOPs should be required to coordinate their plans with other TOPs and BAs in the RC Area. Similarly, BAs should also be required to coordinate their plans with other BAs and TOPs in the RC area. Load shed plans, or other transmission emergencies may require coordination at the TOP level for switching and other similar actions. The RC may not have that detailed visibility or have a role in switching instructions or types of load, critical loads, etc. that the TOP manages. Another important example is load shedding coordination - manual/automatic load shed coordination involves TOP to TOP coordination. For these reasons TOs and BAs should have a coordination role – limiting coordination to just the RC is inappropriate. The revised standard does not include the Communication Protocols from EOP 001 R4.1. While specific communication protocols related to prevention of miscommunications is addressed in the COM standards, it is important that appropriate communications take place between the appropriate entities during emergency operations to support adequate situation awareness for all relevant entities. The EOP standards can facilitate this by making sure all relevant functional entities are identified for issuing and receiving the relevant notices/communications. While the standard does establish relationships between RC, BA, TOP’s; DPs and GOPs are not implicated, and it is arguable that these entities should have appropriate situational awareness during emergency operations. For example, after the RC

notifies the BA, and TOP, likewise the BA and TOP should notify affected DPs and GOPs of the particular emergency. This promotes situational awareness. Additionally while DPs and GOPs play a lesser role, consideration should be given to their inclusion at appropriate levels. DPs should have emergency plans for those emergency actions they need to take, i.e. load shed voltage reduction. GOPs have a role to play and are more appropriate for addressing fuel supply and inventory, fuel switching capabilities, environmental constraints, reduction of internal usage, and most importantly WEATHERIZATION of units. At a minimum, they need to provide this information to the BAs. This is especially true in organized market regions (i.e. ISOs/RTOs). Including DPs and GOPs as appropriate is consistent with their applicability in other standards, such as the communication standards.
No
The inclusion of “NERC” before Energy Emergency Alert is unnecessary and could be problematic potentially from a compliance point of view. EEA is a qualitative term under the NERC standards. The specific system conditions that define EEAs are determined by the relevant regional operational rules. Referring to an EEA as a NERC EEA could be interpreted as implying there is a NERC standard for triggering EEA conditions, which is not true. To mitigate the potential for introducing this ambiguity, the word “NERC” should not be used in conjunction with EEA. Although ERCOT appreciates the intent of R8, the practical implications of the sequence of actions reflected in the standard could be problematic in practice. For example, in ERCOT, where ERCOT is the sole BA and RC, emergency operating plans are used to address EEA events. Yet, under R8 it is contemplated that the BA would exhaust its emergency operating options prior to the declaration of an EEA. This creates a practical disconnect in ERCOT because at that point ERCOT would have been in an EEA situation and executed its relevant emergency procedures. In addition, R8 is problematic due to the removal of the CPS and DCS criteria as part of the original requirement, which were included to highlight the area imbalance and the circumstances where an LSE or BA was imbalanced and leaning on its neighbors to an unacceptable degree. In those circumstances the BA/LSE was required to exercise all available options, , up to and including firm load shed to help protect the interconnection. While the requirements are still similar in nature, some of the sub-requirements are not captured in R2, such as deploying all available operating reserve or requesting emergency assistance.
Group
PacifiCorp

Sandra Shaffer
Yes
Yes
No
R1, Part 1.2.5 does not clearly define required performance. In the proposed requirement, the language ‘coordinated to minimize the use of automatic Load shedding’ does not provide sufficient guidance on the intended load shed policy. The Drafting Team should develop language which provides more specific guidance on how manual Load shedding should be coordinated, and provide a more specific performance measure than ‘minimize the use’ of automatic Load shedding. With respect to the latter, the Drafting Team may want to specifically reference minimizing dependence on under voltage and under frequency Load shedding plans if that is the intention.
No
PacifiCorp supports use of language similar to EOP-003-2 R8 and the language “… timeframe adequate for responding to the emergency.” PacifiCorp annually updates detailed analyses which produce block load shed plans and instructions. Operator training, combined with block load shed plans and instructions, ensures operators are capable of implementing load shedding in a timeframe adequate for responding to an emergency.
Yes
No
R2, Part 2.2.8 does not clearly define required performance. In the proposed requirement, the language ‘coordinated to minimize the use of automatic Load shedding’ does not provide sufficient guidance on the intended load shed policy. The Drafting Team should develop language which provides more specific guidance on how manual Load shedding should be coordinated, and provide a more specific performance measure than ‘minimize the use’ of automatic Load shedding. With respect to the latter, the Drafting Team may want to specifically reference minimizing dependence on under voltage and under frequency Load shedding plans if that is the intention.
No
PacifiCorp supports use of language similar to EOP-003-2 R8 and the language “… timeframe adequate for responding to the emergency.” PacifiCorp annually updates detailed analyses which produce block load shed plans and instructions. Operator training, combined with block load shed plans and instructions, ensures operators are capable of implementing load shedding in a timeframe adequate for responding to an emergency.
Yes

No
While PacifiCorp agrees with the RC having a 30 day period to review a TOP or BA Emergency Operating Plan, it appears that an applicable entity could be out of compliance either during the RC's review, or if the RC withholds approval until certain modifications to the Emergency Operating Plan are completed. The language in R1 and R2 require that a TOP or BA have a "Reliability Coordinator-approved" Emergency Operating Plan, providing no room for interpretation if the RC fails to meet its deadline or additional coordination between neighboring entities is required. This puts a TOP or BA at risk that the RC will reject the Emergency Operating Plan simply to meet its deadline and maintain compliance with R4. The EOP SDT should revise R4 to allow the Reliability Coordinator to either: (1) approve; (2) approve pending modification; (3) or reject a proposed Emergency Operating Plan. This modification will address any issues that may arise out of either the Reliability Coordinator's ability to complete its review in the 30 day review period, and allow an opportunity for the Reliability Coordinator to coordinate between neighboring TOPs and BAs.
Yes
Yes
Yes
Yes
Yes
No
Group
Bonneville Power Administration
Andrea Jessup
Yes
Yes
Yes
Yes

BPA believes clarfication is needed so that a BA may reduce load either directly or through TOP as designed with regard to 2.28 and 2.27
No
BPA believes this applies only if a BA has direct-control load shedding.
Yes
No
BPA believes this approval adds another layer to a wide area responsibility when the issue is mostly between smaller regions. The RC approval is not needed of 40 entities. The RC should direct load shedding through their own plan but they should have copies of the individual plans.
Yes
Yes
Yes
Yes
Yes
Yes
In the section on Alert 3 under Circumstances, BPA believes that the second bullet “Energy Deficient Entity has implemented its approved Emergency Operations Plan” should be removed because Load Serving Entities are included in the definition of Energy Deficient Entities but they do not have “approved Emergency Operations Plans” so this cannot happen when the EDE is an LSE. Also, looking at R2, a BA would be exercising their Plan at least by Alert level 1 so of course they would have implemented it by EEA 3. That bullet is not necessary and is in direct conflict with the fact that LSE's aren’t required to have plans under this standard.
Yes
No
Individual
Lisa Martin
City of Austin dba Austin Energy

Yes
No
City of Austin dba Austin Energy (AE) requests the SDT remove the requirement for the RC to approve each TOP Emergency Operating Plan. Absent technical justification, AE believes the approval process is unnecessary and administratively burdensome. The FERC directive in Order 693, Paragraph 548 requires the SDT to include the RC in the applicability of the standard, not to make the RC approve all Emergency Operating Plans. If the SDT believes the approval is necessary and intends the approval to be limited to the RC coordination effort required in R3, AE requests the SDT include a reference to R3 in R1.
No
City of Austin dba Austin Energy (AE) requests clarification as to whether R1, Part 1.2.5 intends to minimize the overlap between manual Load shed feeders and automatic Load shed (i.e., UFLS and UVLS) feeders. If so, what does “minimize” mean?
Yes
Yes
No
City of Austin dba Austin Energy (AE) believes the RC can coordinate plans without having to approve them.
No
City of Austin dba Austin Energy (AE) finds the phrase “projected System conditions” unclear. AE prefers the TOP requirement be limited to “current System conditions” which is more aligned with the information a System Operator will have in real-time.
Yes
Yes
Yes
No
City of Austin dba Austin Energy (AE) requests clarification on the changes to Attachment 1 and the justification for those changes. Renumbering the EEA levels (and adding an additional

level) could potentially create confusion; the benefit of any changes would need to offset their cost.
Yes
City of Austin dba Austin Energy (AE) could work with either format as long as any changes are identified and justified.
Yes
City of Austin dba Austin Energy (AE) seeks clarity stating the Emergency Operating Plan required under requirement R1 can be a single document or a combination of documents. This is similar to the allowance for a plan or set of plans in currently enforceable EOP-001-2.1b.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments

Project 2009-03 Emergency Operations

The Emergency Operations Drafting Team thanks all commenters who submitted comments on the proposed EOP-011-1 standard. These standards were posted for a 30-day public comment period from March 28, 2014 through April 28, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 40 sets of comments, including comments from approximately 131 different people from approximately 88 companies representing all 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

Index to Questions, Comments, and Responses

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Janet Smith	Arizona Public Service Company	X		X		X	X				
No Additional Responses													
2.	Group	Joseph DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Co	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Coop	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joeseph DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

8. Ken Goldsmith	Alliant Energy	MRO	4
9. Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10. Marie Knox	MISO	MRO	2
11. Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12. Randi Nyholm	Minnesota Power	MRO	1, 5
13. Scott Bos	Muscatine Power & Water	MRO	1, 3, 5, 6
14. Scott Nickels	Rochester Public Utilities	MRO	4
15. Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
16. Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
17. Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3. Group	Connie Lowe	Dominion	X		X		X		X			

Additional Member	Additional Organization	Region	Segment Selection
1. Mike Garton	NERC Compliance Policy	NPCC	5, 6
2. Randi Heise	NERC Compliance Policy	MRO	5
3. Louis Slade	NERC Compliance Policy	RFC	5, 6
4. Larry Nash	Electric Transmission Compliance	SERC	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4. Group	Robert Rhodes	SPP Standards Review Group		X								

Additional Member	Additional Organization	Region	Segment Selection
1. Jeff Elting	Nebraska Public Power District	MRO	1, 3, 5
2. Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5
3. Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
4. Bo Jones	Westar Energy	SPP	1, 3, 5, 6
5. Mike Kidwell	Empire District Electric	SPP	1, 3, 5
6. Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
7. Brandon Levander	Nebraska Public Power District	MRO	1, 3, 5
8. Shannon Mickens	Southwest Power Pool	SPP	2
9. James Nail	City of Independence, MO	SPP	3
10. Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
11. Don Schmit	Nebraska Public Power District	MRO	1, 3, 5
12. Bruce Schutte	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
5. Group	Frank Gaffney	Florida Municipal Power Agency	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Tim Beyrle	City of New Smyrna Beach	FRCC	4
2.	Jim Howard	Lakeland Electric	FRCC	3
3.	Greg Woessner	Kissimmee Utility Authority	FRCC	3
4.	Lynne Mila	City of Clewiston	FRCC	3
5.	Cairo Vanegas	Fort Pierce Utility Authority	FRCC	4
6.	Randy Hahn	Ocala Utility Services	FRCC	3
7.	Stanley Rzad	Keys Energy Services	FRCC	1
8.	Don Cuevas	Beaches Energy Services	FRCC	1
9.	Mark Schultz	City of Green Cove Springs	FRCC	3

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC		10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Matt Goldberg	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1
10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Christina Koncz	PSEG Power LLC	NPCC	5
12.	Helen Lainis	Independent Electricity System Operator	NPCC	2
13.	Michael Lombardi	Northeast Power Coordinating Council	NPCC	10
14.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10

21.	Brian Robinson	Utility Services	NPCC	8
22.	Ayesha Sabouba	Hydro One Networks Inc,	NPCC	1
23.	Brian Shanahan	National Grid	NPCC	1
24.	Wayne Sipperly	New York Power Authority	NPCC	5
25.	Ben Wu	Orange and Rockland Utilities	NPCC	1

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Michael Lowman	Duke Energy	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Doug Hils		RFC	1
2.	Lee Schuster		FRCC	3
3.	Dale Goodwine		SERC	5
4.	Greg Cecil		RFC	6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				

No Additional Responses

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Stuart Goza	SERC OC Review Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ray Phillips	AMEA	SERC	4
2.	Scott Brame	NCEMC	SERC	1, 3, 4, 5
3.	Connie Lowe	Dominion	SERC	1, 3, 6
4.	Terry Bilke	MISO	SERC	2
5.	Marsha Morgan	Southern	SERC	1, 5
6.	Richard Jackson	Alcoa Power Generating Inc.	SERC	5, 6, 7
7.	William Berry	OMU	SERC	3

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Ben Engelby	ACES Standards Collaborators						X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

2. John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
3. Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
4. Ellen Watkins	Sunflower Electric Power Corporation	SPP	1

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Kathleen Black	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Kent Kujala	NERC Compliance	RFC	3
2. Daniel Herring	NERC Training & Standards Development	RFC	4
3. Mark Stefaniak	Regulated Marketing	RFC	5

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. DeWayne Scott		SERC	1
2. Ian Grant		SERC	3
3. David Thompson		SERC	5
4. Marjorie Parsons		SERC	6

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Greg Campoli	ISO/RTO Standards Review Committee		X			X					

Additional Member	Additional Organization	Region	Segment Selection
1. Ali Miremadi	CAISO	WECC	2
2. Cheryl Moseley	ERCOT	ERCOT	2
3. Ben Li	IESO	NPCC	2
4. Matthew Goldberg	ISONE	NPCC	2
5. Terry Bilke	MISO	RFC	2
6. Stephanie Monzon	PJM	RFC	2
7. Charles Yeung	SPP	SPP	2

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Mike O'Neil	Florida Power & Light	X									

No Additional Responses

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Sandra Shaffer	PacifiCorp						X				

No Additional Responses

#	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Fran Halpin	Duty Scheduling	WECC	5									
2.	Rich Ellison	Dispatch	WECC	1									
3.	Jim Burns	Technical Operations	WECC	1									
17.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
18.	Individual	Ronnie C. Hoeinghaus	City of Garland			X							
19.	Individual	Ayesha Sabouba	Hydro One	X		X							
20.	Individual	Dave Willis	Idaho Power Company	X									
21.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				
22.	Individual	Michael Falvo	Independent Electricity System Operator		X								
23.	Individual	John Seelke	Public Service Enterprise Group	X		X	X	X					
24.	Individual	Michelle D'Atnuono	Ingleside Cogeneration LP					X					
25.	Individual	Shirley Mayadewi	Manitoba Hydro	X		X		X	X				
26.	Individual	Keith Morisette	Tacoma Power	X		X	X	X	X				
27.	Individual	Lorraine Landers	Consumers Energy Company			X	X	X					
28.	Individual	Andrew Z. Pusztai	American Transmission Company, LLC	X									
29.	Individual	Anthony Jablonski	ReliabilityFirst										X
30.	Individual	John Brockhan	CenterPoint Energy	X									
31.	Individual	Matt Beilfuss	Wisconsin Electric			X	X	X					
32.	Individual	David Thorne	Pepco Holding Inc.	X		X							
33.	Individual	Scott Langston	City of Tallahassee	X									
34.	Individual	Bill Fowler	City of Tallahassee, TAL			X							
35.	Individual	Karen Webb	City of Tallahassee					X					
36.	Individual	William Temple	Northeast Utilities	X									
37.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
38.	Individual	Joshua Smith	Oncor Electric Delivery Company LLC	X									
39.	Individual	Cheryl Moseley	Electric Reliability Council of Texas, Inc.		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	Lisa Martin	City of Austin dba Austin Energy	X		X	X	X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Agree	Supporting Comments of "Entity Name"
Tennessee Valley Authority	Agree	SERC OC Review Group

1. **Based on the EOP FYRT recommendations, the EOP SDT has combined three standards into the proposed EOP-011-1, Emergency Operations. The original standards are EOP-001-2.1b (Emergency Operations Planning), EOP-002-3.1 (Capacity and Energy Emergencies) and EOP-003-2 (Load Shedding Plans). Do you support the consolidation of these standards? If not, please provide specific recommendations for the EOP SDT in your comments.**

Summary Consideration: The EOP SDT appreciates the support received for Project 2009-03 and in the merging of the three original standards EOP-001-2.1b (Emergency Operations Planning), EOP-002-3.1 (Capacity and Energy Emergencies) and EOP-003-2 (Load Shedding Plans) into one standard, EOP-011-1 Emergency Operations, to provide clarity regarding the critical requirements and to promote coordination and communication across functional entities.

Organization	Yes or No	Question 1 Comment
SPP Standards Review Group	Yes	The work of the SDT in consolidating these standards on emergency operations and clarifying the different requirements between the BA and TOP is appreciated and commendable.
SERC OC Review Group	Yes	The OC Review Group supports the EOP SDT action to combine three standards into the proposed EOP-011-1. Further, the OC Review Group thanks the EOP SDT for their efforts in developing the proposed EOP-011-1.
ACES Standards Collaborators	Yes	We support the consolidation of the three standards, but we question why the drafting team chose to label the new standard as EOP-011-1. Why wouldn't the revised standard be labeled as EOP-001-3? This would be consistent with other drafting team projects and would be less confusing to industry members that do not follow the standards development process that closely. Considering this EOP standard is going to consolidate the key emergency operations standards, it only makes sense to call it EOP-001.

Organization	Yes or No	Question 1 Comment
Idaho Power Company	Yes	Consolidation of the three standards is good, the less redundant standards the better.
Xcel Energy	Yes	Xcel Energy supports moving to a single standard as it will leave less room for potential conflicts between multiple documents.
Ingleside Cogeneration LP	Yes	Ingleside Cogeneration LP (ICLP) supports the project team's efforts to clearly separate compliance responsibilities by entity. In our view, the mixing of TOP and BA requirements in the existing standards has only served to introduce confusion - leading the possibility open that both or neither entity will take these actions. This leads to a reliability gap that we believe EOP-011-1 successfully addresses.
Consumers Energy Company	Yes	Agree that the merging of the three standards will provide clarity of the critical requirements and promoting coordination and communication across functional entities
American Transmission Company, LLC	Yes	ATC supports the consolidation of the noted EOP standards into the proposed EOP-011-1. However, ATC recommends that Parts R1.2.1 - R1.2.6 and R1.3 of Requirement R1 be rewritten as detailed in the response to Question 2.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Florida Municipal Power Agency	Yes	
Northeast Power Coordinating Council	Yes	

Organization	Yes or No	Question 1 Comment
Duke Energy	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
DTE Electric	Yes	
ISO/RTO Standards Review Committee	Yes	
Florida Power & Light	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
American Electric Power	Yes	
City of Garland	Yes	
Hydro One	Yes	
Independent Electricity System Operator	Yes	
Public Service Enterprise Group	Yes	

Organization	Yes or No	Question 1 Comment
Manitoba Hydro	Yes	
Tacoma Power	Yes	
ReliabilityFirst	Yes	
CenterPoint Energy	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	
Northeast Utilities	Yes	
Lincoln Electric System	Yes	
Oncor Electric Delivery Company LLC	Yes	
City of Austin dba Austin Energy	Yes	

2. **The EOP SDT has developed proposed Requirement R1 to specify the minimum set of elements required for the Transmission Operator to include in their Emergency Operating Plan. Do you agree with the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language.**

Summary Consideration: The EOP SDT discussed the many suggestions received for Requirement R1 and its detailed requirement parts. Based on comments received, the EOP SDT added details into the Requirement R1 Rationale that if any Requirement R1 Parts are not applicable, that the Transmission Operator should note "not applicable" in their plan. There were also updates, additions and deletions made to the requirement parts to lend more clarity and to streamline the requirement and requirement parts, as the industry comments had suggested.

Organization	Yes or No	Question 2 Comment
MRO NERC Standards Review Forum	No	Since R1.1 is part of the Operating Plan, an entity does not need a "Definition of" roles and responsibilities. Recommend to remove "Definition of" in R1.1. R1.2, Since an Operating Plan is defined as a procedure or process, recommend deleting "Procedures, processes or" from R1.2. R1.2.2 should contain the cancelling or recalling of generation outages too. R1.3, recommend to add "topology or System configuration" at the end of R1.3. This further defines that a major change will need to be accomplished in order to review your Emergency Operating Plan. Note that this Requirement (Federal Law) gives the entity a bright line to when a change has to me made. The entity can make any change at any time regardless of this bright line criteria.
Dominion	No	Part 1.2.6 says 'Strategies to be used to mitigate reliability impacts of extreme weather conditions.' Part 2.2.9 says 'Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan.' Dominion suggests revising Part 1.2.6 to read "Strategies for addressing reliability impacts of extreme weather, if not covered by other elements of the plan." which has the same caveat for coverage by other elements of the plan as Part 2.2.9.

Organization	Yes or No	Question 2 Comment
SPP Standards Review Group	No	We agree with the intent of the SDT to create a separate requirement for Transmission Operators to have an Emergency Operating Plan. Unfortunately, the requirement actually combines three requirements (development, maintenance and implementation) into a single requirement. We recommend splitting each of these into separate requirements. Additionally, the Time Horizon for development and maintenance of the Emergency Operating Plan is different than that for implementation. It may be more appropriate to include implementation of the Emergency Operating Plan to prevent or mitigate operating Emergencies on its Transmission System within R5. Also, the Violation Risk Factors for development and maintenance of the plan should be “Medium”, while the Violation Risk Factor for implementation should be “High”. Corresponding changes to M1 would need to be made to reflect these proposals. The measurement for implementation is also troubling as registered entities may be in the position of having to prove a negative if they do not have an Emergency during an audit period. Additionally, we request clarification on the intent of the term ‘implement’ in R1. Does this mean simply disseminating the Plan throughout your organization including providing it to your operators? Or does this mean activating your Plan when an Emergency occurs? If it’s the former, then it fits this requirement and we would propose the SDT use ‘disseminate’ or ‘issue’ for the term. However, if it is the latter, then it doesn’t belong in this requirement but perhaps in R5. It seems that the intent could be the latter since the SDT used implement again in Part 1.1 in conjunction with activate. The Emergency Operating Plan, specified in R1, should include the requirement to notify the TOP’s RC of its current and projected System conditions. R5 would then simply require implementation of the plan. (See our comment in Question 10 below.)Part 1.3. is not clear. An emergency plan that includes procedures, processes and strategies, may not need to be revised for every change to the TOP’s System. The requirement does not include any periodic review. Is the intent of the SDT that the process include some periodic review or is that entirely up to the TOP? As currently stated, the scope is entirely too broad. In the 2nd line of M1, insert a space between ‘R1’ and ‘that’.

Organization	Yes or No	Question 2 Comment
Florida Municipal Power Agency	No	Does the RC really need to approve, or should it be a coordination requirement? If so, then there ought to be a description of what types of changes ought to require approval and what changes do not, e.g., do minor changes such as phone number updates need to be approved?
Duke Energy	No	(1)Duke Energy questions the need to require a BA/TOP have its Emergency Operating Plan approved by a Reliability Coordinator. On its face, there doesn't appear to be a clear Reliability-based need to have an BA/TOP's individual Emergency Operating Plan approved, and respectfully requests that the SDT provide more clarity on the technical justification for requiring RC-approval. If the Reliability-based need is not readily attainable, the standard/requirement should be viewed as purely administrative in nature, and be treated as unduly burdensome. (2)R1.2.4:As written, R1.2.4 is not clear on what is meant by "Processes for redispatch of generation". Is it the intent of the SDT to have the TOP work with the other Functions involved? If this is the intent of the SDT, it should be explicitly stated that a TOP must work with other Functions involved for a process on the redispatch of generation. "Process for requesting the redispatch of generation."(3)The EOP SDT has used the term "Emergency Operating Plan" in R1. as a NERC defined term by capitalizing. Duke Energy believes the intent of this term is to combine the definitions of "Emergency" and "Operating Plan" from the NERC Glossary, but recommends the SDT to take this under consideration. The use of Operating Plan in the requirement is the correct and consistent approach since it is our understanding that the NERC SDT's have been guided to use defined terms and not use terms such as plan, process, and procedure to eliminate any ambiguity. Because of this approach, Duke Energy questions the use of Plans, Processes, and Strategies in R1.2. and at the beginning of each sub-requirement to R1.2. with the exception of R1.2.5., which has been written differently. The NERC term Operating Plan is defined as, "A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units,

Organization	Yes or No	Question 2 Comment
		Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan." (4)Because the definition of Operating Plan includes "Operating Procedures" and "Operating Processes" (both are NERC defined terms), we recommend the use of these terms in the sub-requirements to be consistent with the direction of other standards that are currently effective or under development. The use of the term "Strategies" will also need to be considered by the SDT to either be replaced with one of the NERC defined terms or propose a new term "Operating Strategies" for comment during the development of Reliability Standard EOP-011-1. (5)R1.2.6:Duke Energy feels as though this requirement is overly broad, and could possibly be viewed as a candidate for Paragraph 81 criteria. Strategies to mitigate reliability impacts of extreme weather are not "one-size fits all". Not all regions experience the same extreme weather conditions, which could make this requirement difficult to audit against. Duke Energy suggests placing objective and clearly quantifiable measures and VRF/VSL(s) in place to assist a TOP in ascertaining the responsibilities expected for audit purposes." Identify strategies used to mitigate adverse reliability impacts of extreme weather events."
SERC OC Review Group	No	The OC Review Group is concerned with the phrase "At a minimum" as it is possible that certain elements may not be applicable to a certain TOP. It is recommended that the term "applicable" be utilized. Current R1 language: R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include the following elements: Proposed R1 language: R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. The Emergency Operating Plan shall include the applicable elements when developing an Emergency Operating Plan:
ACES Standards Collaborators	No	(1) We see several issues with these proposed requirements. First, the term "Emergency Operations Plan" is not a defined term. This should either be lowercase

Organization	Yes or No	Question 2 Comment
		or the SDT should propose to add it to the NERC glossary. (2) The glossary term "Energy Emergency" is not the same as "Energy Emergency Alert." The supplemental document showing each standard that uses the term has incorrectly identified an EEA. We recommend reviewing the standards again to verify that the revision to the glossary term does not impact standards that use the word "emergency" in the requirements. (3) The RC approval process is an administrative action that does not support reliability. The approval process should be completed internally. This process is a burden for RCs and registered entities, especially smaller entities that may not have an impact on the reliability of the RC Area. Having an internal approval that aligns with the RC emergency plans would satisfy the intent of the requirement, but would also limit the administrative functions that relate to getting an approval from the RC. The requirement could state that the plans must align with RC emergency plans, which are posted and available to all registered entities in the RC Area. Verifying this information is much simpler if done internally, instead of burdening RC staff with approving each member's plan. As an alternative, the RC could be required to simply review the plans for conflicts. (4) Does the RC need to approve every change to the plan? Within what timeframe? The standard is not clear regarding the process for getting RC approval and secondary approvals for subsequent changes. Again, this is administrative in nature. (5) Requirement R1, part 1.3, meets Paragraph 81 criteria because it is completely administrative. There is no reason that a standard needs to require the details of a revision process. The requirement already has the word "maintain" in relation to the plan, which implies that updates will be made when necessary. This should be removed.
Florida Power & Light	No	This new requirement is too prescriptive, specifically requirement 1.2 where it defines minimum requirements a BA should include in the Emergency Operating Plan. Some of these requirements may not apply to all BAs.

Organization	Yes or No	Question 2 Comment
American Electric Power	No	AEP believes R1.2.4 (Processes for redispatch of generation) is applicable to the Balancing Authority, and *not* the Transmission Operator (who does not redispatch generation).
Xcel Energy	No	R1 and R2 language is strict in that an entity's EOP "shall include" elements defined in R1.1 to R1.3 and R2.1 to R2.3 respectively. What will happen in a situation where one of those elements does not apply to an entity? This standard is implying that all the elements identified in R1.1 to R1.3 and R2.1 to R2.3 must be included in the EOP whether they are applicable or not. The current EOP-001 R4 allows for in its Attachment 1 to be omitted if they are not applicable ("shall include the applicable elements"). We feel like the new EOP-011 standard should include similar language to allow for this flexibility. Could the Standard Drafting Team respond why the language in EOP-011 R1 and R2 was written to be more restrictive than the current EOP-001 R4 and whether items in R1.1 to R1.3 or R2.1 to R2.3 could be omitted from an EOP if found to be not applicable to an entity? Additionally, the word "develop" should be removed from the requirement. Every entity should have a plan today. It should be maintained and implemented. IF an entity does not have a plan, it will have to develop one to have one to implement. The requirement does not need to address this issue.
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration: 1. Requirement R1 and R2 - ReliabilityFirst believes the "implement a Reliability Coordinator-approved Emergency Operating Plan" language is troublesome in a scenario where a Reliability Coordinator disapproves the Emergency Operating Plan (per Requirement R4). In this scenario, the Transmission Operator/Balancing Authority could be compliant with developing and maintaining the plan but without Reliability Coordinator approval of the plan, the Transmission Operator/Balancing Authority could potentially be deemed non-compliant with Requirement R1 and R2. ReliabilityFirst believes the "implement a Reliability Coordinator-approved Emergency Operating Plan" language should be taken out of Requirements R1 and R2 respectively. ReliabilityFirst

Organization	Yes or No	Question 2 Comment
		recommends including a new Requirement R5 which states “Upon Reliability Coordinator approval of the Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans, the Transmission Operator and Balancing Authority shall implement the approved Emergency Operating Plan.”
CenterPoint Energy	No	CenterPoint Energy has concerns with Requirement R1 as drafted and offers the following recommendations. One, CenterPoint Energy is concerned that, as drafted, Requirement R1 restricts TOPs to one single Emergency Operating Plan. The Company believes TOPs should be able to utilize multiple plans to address R1, as long as the plans in aggregate include all the required elements. Two, CenterPoint Energy does not support requiring the RC to approve the TOP’s Emergency Operating Plans. Paragraph 548 of Order 693 only directed that the RC be added as an applicable entity, not for the RC to assume approval responsibility. Thus, to incorporate suggestions 1 and 2, the proposed Requirement R1 should be revised to state: “Each Transmission Operator shall develop, maintain, and implement one or more Emergency Operating Plans to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plans shall include the following elements:”. Three, CenterPoint Energy believes R1 Part 1.1 is unnecessary. TOP-001-1a Requirement R1 states that Transmission Operators have the responsibility and clear decision-making authority to take whatever actions necessary to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies. TOP 001-1a R2 also states that, “Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment, shedding firm load, etc.” Further definition of roles and responsibilities are unnecessary. CenterPoint Energy recommends R1 Part 1.1 be deleted. Four, CenterPoint Energy believes R1 Part 1.2.1 is duplicative of various existing requirements. TOP-004-2 R6 already requires TOPs to have policies and procedures that address monitoring and controlling of voltage levels that impact reliability. Additionally, VAR-001-3 R1 and R2 require TOPs to have sufficient reactive resources for Contingency conditions and to have formal policies and procedures for monitoring and controlling voltage levels.

Organization	Yes or No	Question 2 Comment
		CenterPoint Energy believes Part 1.2.1 is unnecessary and should be deleted from the proposed EOP-011-1. Five, CenterPoint Energy believes the “extreme weather conditions” referenced in R1 Part 1.2.6 is vague, and it would be challenging for TOPs and auditors to interpret what qualifies as “extreme”. CenterPoint Energy believes that not all events of “extreme” weather result in emergency conditions requiring special mitigation strategies. In addition the Company believes that various existing operational planning requirements are sufficient to cover preparedness for extreme weather, such as TOP-005-2a R2 and Attachment 1 and TOP-006-2 R4. Therefore, Part 1.2.6 is unnecessary and should be deleted. If, however, the SDT insists on retaining such a requirement, CenterPoint Energy recommends Part 1.2.6 be revised to state: “Strategies to be used to mitigate reliability impacts of extreme weather conditions defined by the Transmission Operator.”
Pepco Holding Inc.	No	Why not include many of the other elements included in R2 for Transmision Emergencies?
City of Tallahassee	No	The language from R1.2.6 referring to the potential impacts of extreme weather is difficult to quantify. Due to the lack of specificity, TAL would create “high level strategies” similar to those created for restoration from black start resources. Also, requiring the RC to approve the plan places an administrative burden on both the entity and the RC.
City of Austin dba Austin Energy	No	City of Austin dba Austin Energy (AE) requests the SDT remove the requirement for the RC to approve each TOP Emergency Operating Plan. Absent technical justification, AE believes the approval process is unnecessary and administratively burdensome. The FERC directive in Order 693, Paragraph 548 requires the SDT to include the RC in the applicability of the standard, not to make the RC approve all Emergency Operating Plans. If the SDT believes the approval is necessary and intends the approval to be limited to the RC coordination effort required in R3, AE requests the SDT include a reference to R3 in R1.

Organization	Yes or No	Question 2 Comment
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Southern requests clarification on the term “Emergency Operating Plan.” Did the SDT intend for “Emergency Operating Plan” to be a new term or is the meaning associated with each term separately: “Emergency” and “Operating Plan.”This standard reemphasizes a widespread concern that the definition of “Emergency” in the NERC Glossary is too broad to make it possible to create this document. We feel that an Emergency Operating Plan should exist for significant operating conditions and not the full spectrum of conditions that the current Emergency term encompasses.
Idaho Power Company	Yes	The minimum set of requirements is fine. I question that the plan needs to be approved by the Reliability Coordinator. If during an audit a plan is found to be deficient by the auditors but has been approved by the Reliability Coordinator where does the liability fall, With the Transmission Operator or the RC as the approver of the plan?1.2.4. Redispatch of Generation- seems more like a BA function than a TOP function.
American Transmission Company, LLC	Yes	ATC agrees with the wording of the proposed Requirement R1. However, ATC recommends that Parts R1.2.1 - R1.2.6 of Requirement R1 be rewritten as: R1.2.1 - Controlling voltage;R1.2.2 - Cancelling or recalling Transmission outages;R1.2.3 - System reconfiguration;R1.2.4 - Redispatch of generation; R1.2.5 - Manual load shedding designed to minimize the reliance on automatic load shedding;R1.2.6 - Mitigation of reliability impacts of extreme weather conditions; The changes to Parts R1.2.1 - R1.2.6 eliminate references to documentation that is previously specified in Part 1.2 of Requirement R1. The revision of Part 1.2.5 also provides clarification regarding the relationship between manual and automatic load shedding. In addition, ATC recommends that Part R1.3 be rewritten as “A process for reviewing its Emergency Operating Plan on an annual basis to evaluate the impact of changes to its System and revising the Emergency Operating Plan accordingly.” This revision

Organization	Yes or No	Question 2 Comment
		specifies an “annual” time requirement to the Emergency Operating Plan review and revision process.
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council	Yes	
DTE Electric	Yes	
ISO/RTO Standards Review Committee	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
City of Garland	Yes	
Hydro One	Yes	
Independent Electricity System Operator	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	

Organization	Yes or No	Question 2 Comment
Tacoma Power	Yes	
Consumers Energy Company	Yes	
Wisconsin Electric	Yes	
Northeast Utilities	Yes	
Lincoln Electric System	Yes	
Oncor Electric Delivery Company LLC	Yes	

3. The EOP SDT has developed proposed Requirement R1, Part 1.2.5 as a process to include manual Load shedding plan coordination. Do you agree that Requirement 1, Part 1.2.5 clearly defines required performance? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: In Requirement R1, Part 1.2.6., the EOP SDT has added the term "Operator-controlled" preceding the language "manual Load shedding," as it was in the currently-enforced standard, EOP-003-2 Requirement R8. The EOP SDT also agrees that the intent of UFLS is meant as all automatic Load shedding, including UVLS, if applicable; but to still largely maintain separate "plans" for manual and automatic Load shedding. It is the EOP SDT's intention that entities would strive to maintain an operator-controlled manual Load shedding plan that is largely separate and distinct from their automatic Load shed plans. The EOP SDT also understands that when, for example, localized Load shedding is needed, that it may need to include feeders that are part of any automatic Load shed system.

Conversely, for Capacity Emergencies, if operator-controlled Load shedding is needed, it is desirable to avoid feeders with automatic Load shedding, such that automatic Load shedding functionality is maintained.

Organization	Yes or No	Question 3 Comment
MRO NERC Standards Review Forum	No	We believe that the "automatic Load shedding" is either UFLS or UVLS (and maybe an SPS/RAS). It is very hard to (and impossible) "coordinate" an automatic system with a manual system. Since R1.2.5 is an element of the Emergency Operating Plan, recommend R1.2.5 to read: Manual Load shedding plan(s) incorporated to minimize the use of automatic Load shedding;". This will allow the entity to have a preconceived (pre-planned) process for when the risk is higher that an automatic Load shedding may occur
Dominion	No	Dominion is concerned that this could be read as requiring manual (human at station) load shed as opposed to automatic (SCADA) when we believe the intent is to coordinate so as to avoid overlap with UFLS and UVLS programs. We suggest 1.2.5 read as 'Operator controlled manual Load shedding plan coordinated to minimize the use of UFLS and UVLS automatic Load shedding.' In which operator controlled manual load shedding was used in EOP-003-2.
SPP Standards Review Group	No	The phrase "coordinated to minimize the use of automatic Load shedding" in Requirement 1, Part 1.2.5 is not clear. Is the intent to coordinate the manual Load shedding plan with those locations that have automatic Load shedding installed so as not to duplicate the same Load in both manual and automatic plans? Or is the intent to develop a manual Load shedding plan that will be enacted quickly enough so that automatic Load shedding is minimized? If it is the former, we suggest revised language for Part 1.2.5.: "Manual Load shedding plan coordinated to minimize the use of locations with automatic Load shedding;". We may even go further to propose deleting the phrase "to minimize the use of automatic load shedding" entirely as this seems to be a bit of editorializing. If it is the latter, then the reason for having a

Organization	Yes or No	Question 3 Comment
		manual Load shedding plan is immaterial in the standard. It definitely needs to be in your Emergency Operating Plan, just not in the standard.
Florida Municipal Power Agency	No	1.2.5 ought to be specific to UVLS and should not apply to UFLS. A TOP has no role in manual load shedding to address a capacity / energy emergency to coordinate with UFLS. It is unrealistic to expect load shedding for purposes of solving local transmission problems to retain enough load in the local area to then be able to participate fully in the UFLS program, e.g., it may be necessary to shed all of the load at a particular substation to solve an overload due to multiple contingencies on the transmission system, which will mean that the UFLS relays on the feeders at that substation will not participate in a subsequent UFLS event. Missing those limited number of UFLS relays will not have a meaningful effect on the effectiveness on a UFLS program which is more regional in nature.
Northeast Power Coordinating Council	No	We agree with the need to coordinate manual load shedding with other load shedding actions, but Part 1.2.5 falls short of with whom or with which plans a TOP needs to coordinate its manual load shedding plan. We suggest expanding this part as follows:1.2.5 Manual Load shedding plan coordinated with automatic loading programs to minimize the use of automatic Load shedding, and also coordinated with the manual load shedding plans of other entities in the Reliability Coordinator Area to avoid insufficient or excessive manual load shedding.
Duke Energy	No	R1.2.5:Duke Energy requests clarification on the intent of R1.2.5. Is it the intent of the SDT for a TOP to coordinate a Manual Load Shedding Plan to reduce the double counting of load used in an Automatic Load Shedding Scheme, or to reduce the overall dependency on the use of Automatic Load Shedding? A re-wording is needed to clearly state the purpose of this requirement. Also, we request further explanation as to what the SDT means by using the term “coordination” in the requirement. Further explanation as to what the SDT means by using “coordination” could provide some clarity on how a TOP can minimize the use of Automatic Load Shedding in favor of a Manual Load Shedding Plan. Duke Energy is of the opinion that the term

Organization	Yes or No	Question 3 Comment
		"minimize" as used in the requirement is difficult to quantify, and is not a term equated with Auditability.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	Southern does not agree that R1, Part 1.2.5 clearly defines required performance. Southern recommends that the SDT modify the rationale included in the standard or the technical background and rationale document to clearly explain the intent of the requirement.
SERC OC Review Group	No	The OC Review Group recommends that adding "Operator controlled" further clarifies R1, Part 1.2.5R1, Part 1.2.5. Current language: Manual Load shedding plan coordinated to minimize the use of automatic Load shedding;R1, Part 1.2.5 Proposed language: Operator controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding;
ACES Standards Collaborators	No	(1) It is not clear what parties are supposed to coordinate their plans. Coordination is an ambiguous term that could be interpreted in multiple ways. The measure does not provide any additional guidance on what is expected for coordination and the drafting team did not provide compliance guidance or an RSAW with this draft. Are TOPs supposed to coordinate with other TOPs? Other BAs? Or is the standard proposing that the RC approval process is evidence of coordination? This is not clear and needs to be revised. The bottom line is that coordination is a vague requirement that needs to be further refined to clearly spell out what is required for coordination.

Organization	Yes or No	Question 3 Comment
Florida Power & Light	No	Requirement not clear. Is this requirement intended to use the manual load shed to prevent automatic load shed; or is it to ensure that the same resource is not used for manual and automatic load shed.
PacifiCorp	No	R1, Part 1.2.5 does not clearly define required performance. In the proposed requirement, the language 'coordinated to minimize the use of automatic Load shedding' does not provide sufficient guidance on the intended load shed policy. The Drafting Team should develop language which provides more specific guidance on how manual Load shedding should be coordinated, and provide a more specific performance measure than 'minimize the use' of automatic Load shedding. With respect to the latter, the Drafting Team may want to specifically reference minimizing dependence on under voltage and under frequency Load shedding plans if that is the intention.
American Electric Power	No	AEP does not endorse the current draft of EOP-011-1 R1.2.5 as it is too prescriptive. There could be situations where it is desirable to use UVLS instead of manual load shed since an operator could not shed load fast enough. As a concrete example, consider a situation where there are two major 138kV feeds into an area. If one feed is out of service, and the other were to trip, there would be severe voltage depression with the only the subtransmission support unless UVLS is quickly utilized. It is not clear what the SDT intention is with 1.2.5 as it relates to minimizing risk to the Bulk Electric System.
Idaho Power Company	No	No. Automatic load shedding would include under-voltage and under-frequency load shedding which would happen as the result of relay operation. An Operator may not have adequate time to manually shed load to prevent automatic load shedding. The automatic schemes are in place to protect the BES as they should be. I think the requirement should not focus on coordination as much as having a manual load shedding plan.As part of 1.2, it should say "Processes for manual load shedding."

Organization	Yes or No	Question 3 Comment
Xcel Energy	No	There is no defined performance because of the use of the word "minimize". Does this mean any use of automatic load shedding violates the standard? If so, entities should remove any automatic load shedding capability so they do not violate the standard. However, that will put the interconnection at greater risk, which is not the goal of the standards. As written, there is no clear measurement process. It would have to be argued on a case by case basis and an auditor/regulator can argue any automatic load shedding violates the standard. This is a detail that can not be properly addressed in a standard as the specifics will vary with each entity.
Public Service Enterprise Group	No	The requirement for a coordinated manual Load shedding plan is a good one. However, the TOP should coordinate its plan with its LSEs, DPs, and their respective BAs. BAs should be added to the TOP coordination because a manual Load shedding plan is also required in R2 for BAs. The two entities (TOP and BA) should coordinate their manual Load shedding plans among themselves before submitting such plans to their RC for approval. Part 1.2.5 should therefore be modified as follows: "Manual Load shedding plan coordinated [ADD: among its Load Serving Entities and Distribution Providers and their respective Balancing Authority(ies) ....]"
Manitoba Hydro	No	(1) R1.2.5 contains a requirement that manual Load shedding be coordinated, but does not specify with whom the Load shedding should be coordinated. The coordinating entities should be specified.
Tacoma Power	No	Tacoma Power is unsure if the intent is: a) for the System Operator to minimize manually shedding facilities that have automatic load shedding equipment installed in lieu of facilities that do not, -OR- b) to utilize manual load shedding (preemptively) to attempt to forestall automated load shedding from occurring.
American Transmission Company, LLC	No	ATC agrees with the wording of the proposed Requirement R1, but recommends that Part 1.2.5 be modified to "Manual load shedding designed to minimize the reliance

Organization	Yes or No	Question 3 Comment
		on automatic load shedding;" This revision provides clarification regarding the relationship between manual and automatic load shedding.
Wisconsin Electric	No	It is not clear what or with whom coordination is required. The proposed standard "Rationale for R1" section indicates that TOP and BA load shedding "sometimes" needs to be coordinated. However, neither R1 (TOP requirement) nor R2 (BA requirement) explicitly require coordination between the two.
City of Tallahassee	No	TAL is confused by R1.2.5. Is the intent not to overlap manual and automatic (UFLS) load shed tools (i.e. feeder circuits) or is the intent to require manual load shedding prior to activation of automatic load shedding? The verbiage does not specify who must be part of the coordination effort.
Lincoln Electric System	No	Recommend additional clarification be added to Part 1.2.5 to specify whether the loads used by the operators in a Manual Load Shedding plan are either used last, or not at all, in comparison to the loads that are already defined in any automatic under-frequency or automatic under-voltage load shed plans.
City of Austin dba Austin Energy	No	City of Austin dba Austin Energy (AE) requests clarification as to whether R1, Part 1.2.5 intends to minimize the overlap between manual Load shed feeders and automatic Load shed (i.e., UFLS and UVLS) feeders. If so, what does "minimize" mean?
ISO/RTO Standards Review Committee	Yes	We agree with the need to coordinate manual load shedding with other load shedding actions, but Part 1.2.5 appears to fall a bit short of with whom or with which plans a TOP needs to coordinate its manual load shedding plan. We suggest expanding this part, and add a new part as follows:1.2.5 Manual Load shedding plan coordinated with automatic load shedding programs to minimize the use of automatic Load shedding;1.2.6 Manual Load shedding plan coordinated with the manual load shedding plans of other entities in the Reliability Coordinator Area to avoid insufficient or excessive manual load shedding;

Organization	Yes or No	Question 3 Comment
Independent Electricity System Operator	Yes	We agree with the need to coordinate manual load shedding with other load shedding actions, but Part 1.2.5 appears to fall a bit short of with whom or with which plans a TOP needs to coordinate its manual load shedding plan. We suggest to expand this part as follows:1.2.5 Manual Load shedding plan coordinated with automatic loading programs to minimize the use of automatic Load shedding, and the manual load shedding plans of other entities in the Reliability Coordinator Area to avoid insufficient or excessive manual load shedding.
Northeast Utilities	Yes	We agree with the need to coordinate manual load shedding with other load shedding actions, but Part 1.2.5 appears to fall a bit short of with whom or with which plans a TOP needs to coordinate its manual load shedding plan. We suggest expanding this part as follows:1.2.5 Manual Load shedding plan coordinated with automatic loading programs to minimize the use of automatic Load shedding, and also coordinated with the manual load shedding plans of other entities in the Reliability Coordinator Area to avoid insufficient or excessive manual load shedding.
Arizona Public Service Company	Yes	
DTE Electric	Yes	
Bonneville Power Administration	Yes	
City of Garland	Yes	
Hydro One	Yes	
Consumers Energy Company	Yes	

Organization	Yes or No	Question 3 Comment
Pepco Holding Inc.	Yes	
Oncor Electric Delivery Company LLC	Yes	

4. **The EOP SDT has developed proposed EOP-011-1, Requirement R1, Part 1.2.5 without a specific time measure. The currently-enforceable EOP-003-2, Requirement R8 states, "… timeframe adequate for responding to the emergency." Do you support Requirement R1, Part 1.2.5 without a time measure? If not, please provide specific suggestions for improvement, including alternate language**

Summary Consideration: The EOP SDT agrees that the time frame may vary by the request of the Reliability Coordinator or Transmission Operator as a directive. If a directive cannot be performed in the time frame requested, the process (per TOP-001-1, IRO-001 [as well as other standards]) is to report this information back to the Reliability Coordinator/Transmission Operator so that further actions can be taken to mitigate the event. The rationale for Requirement R2 states that an Emergency plan may sometimes require coordination between the Balancing Authority and the Transmission Operator. The EOP SDT held discussion to emphasize the importance of coordination between the Balancing Authority and Transmission Operator in any type of event pertaining to manual Load shed and in addressing how a directive should be handled, regardless of the content of the directive.

Organization	Yes or No	Question 4 Comment
SPP Standards Review Group	No	One of the issues identified in previous events has been that some entities have manual Load shedding plans that require dispatching personnel to dispersed locations to implement the plan. The standard should include a requirement that manual Load Shedding be able to be implemented in time to mitigate the Emergency. We suggest the requirement include that the Manual Load shedding plan be capable of being implemented by an operator remotely. This addresses the issue of not being able to respond quickly to a given situation while at the same time eliminating the ambiguity of maintaining the existing language in EOP-003-2, R8.
PacifiCorp	No	PacifiCorp supports use of language similar to EOP-003-2 R8 and the language "... timeframe adequate for responding to the emergency." PacifiCorp annually updates detailed analyses which produce block load shed plans and instructions. Operator training, combined with block load shed plans and instructions, ensures operators are

Organization	Yes or No	Question 4 Comment
		capable of implementing load shedding in a timeframe adequate for responding to an emergency.
Tacoma Power	No	The current EOP-003-2 R8 language "timeframe adequate for responding to the emergency" should remain. Load shedding plans that are not viable (i.e. the System Operator has no hope of actually executing the plan quickly enough to mitigate the emergency) are useless. Tacoma Power fears that without this measurement, plans that are not actually useful may be created.
Northeast Power Coordinating Council	Yes	There are other standards with requirements in place to mitigate emergency conditions (e.g. IROL violations) in specific time frames. Imposing another time frame creates the potential for having multiple violations for the same infraction.We agree with not specifying a time frame since the time required to implement and complete manual load shedding will depend on a number of conditions, such as: the completion of the automatic load shedding and its effects on mitigation, the time needed for manual load shedding to be completed from the time of initiation, other available actions that may be taken prior to shedding load, etc. The reliability driver is to arrest/mitigate Emergency as soon as possible. System Operators will have this reliability driver in mind when faced with an Emergency, and are the best judge to determine when should manual loading be initiated and completed.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company	Yes	Other standards adequately cover the time frame requirements.

Organization	Yes or No	Question 4 Comment
Generation and Energy Marketing		
ACES Standards Collaborators	Yes	We support manual firm load shedding without a specific time measure. However, we are concerned the compliance monitoring approaches may create a de facto time requirement. We would like to see guidance or an RSAW to state how this will be evaluated.
ISO/RTO Standards Review Committee	Yes	We agree with not specifying a time frame since the time required to implement and complete manual load shedding will depend on a number of conditions, such as: the completion of the automatic load shedding and its effects on mitigation, the time needed for manual load shedding to be completed from the time of initiation, other available actions that may be taken prior to shedding load, etc. The reliability driver is to arrest/mitigate an Emergency as soon as possible. System Operators will have this reliability driver in mind when faced with an Emergency, and are the best judges of when manual load shedding should be initiated and completed.
Xcel Energy	Yes	The time frame is determined by the emergency. The current language is impossible to fairly enforce. Therefore, it should be removed. We support the drafting team's position on this issue.
Independent Electricity System Operator	Yes	We agree with not specifying a time frame since the time required to implement and complete manual load shedding will depend on a number of conditions, such as: the completion of the automatic load shedding and its effects on mitigation, the time needed for manual load shedding to be completed from the time of initiation, other available actions that may be taken prior to shedding load, etc. The reliability driver is to arrest/mitigate Emergency as soon as possible. System Operators will have this reliability driver in mind when faced with an Emergency, and are the best judge to determine when should manual loading be initiated and completed.
Pepco Holding Inc.	Yes	Don't need to duplicate the same requirement in different Standards.

Organization	Yes or No	Question 4 Comment
American Transmission Company, LLC	Yes	ATC supports Requirement R1, Part 1.2.5 without a time measure because time measures are defined in the applicable TOP standards. However, ATC recommends Part 1.2.5 be modified to “Manual load shedding designed to minimize the reliance on automatic load shedding;” This revision provides clarification regarding the relationship between manual and automatic load shedding.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Florida Municipal Power Agency	Yes	
Duke Energy	Yes	
SERC OC Review Group	Yes	
DTE Electric	Yes	
Florida Power & Light	Yes	
Bonneville Power Administration	Yes	
American Electric Power	Yes	
City of Garland	Yes	

Organization	Yes or No	Question 4 Comment
Hydro One	Yes	
Idaho Power Company	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	
CenterPoint Energy	Yes	
Wisconsin Electric	Yes	
City of Tallahassee	Yes	
Northeast Utilities	Yes	
Lincoln Electric System	Yes	
Oncor Electric Delivery Company LLC	Yes	
City of Austin dba Austin Energy	Yes	

5. The EOP SDT developed Requirement R2 to specify the minimum set of elements required for the Balancing Authority to include in their Emergency Operating Plan. Do you agree with the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: The EOP SDT discussed the many suggestions received for Requirement R2 and its detailed requirement parts. Based on comments received, the EOP SDT added details into the Requirement R2 rationale that if any Requirement R2 Parts are not applicable, that the Balancing Authority should note "not applicable" in their plan. There were also updates, additions and deletions made to the requirement parts to lend more clarity and to streamline the requirement and requirement parts, as the industry comments had suggested.

Organization	Yes or No	Question 5 Comment
MRO NERC Standards Review Forum	No	Since R2.1 is part of the Operating Plan, an entity does not need a "Definition of" roles and responsibilities. Recommend to remove "Definition of" in R2.1. R2.2, Since an Operating Plan is defined as a procedure or process, recommend deleting "Procedures, processes or" from R2.2. R2.3, recommend to add "topology or System configuration" at the end of R2.3. This further defines that a major change will need to be accomplished in order to review your Emergency Operating Plan. Note that this Requirement (Federal Law) gives the entity a bright line to when a change has to me made. The entity can make any change at any time regardless of this bright line criteria.
Dominion	No	The last sentence in R2 Dominion suggests adding "the following elements:" for consistency with R1.What is meant by Governmental programs in 2.2.4, this needs more description or some examples? Are governmental programs exclusive of 2.2.2, 2.2.3 and 2.2.7 and if so, why are they

Organization	Yes or No	Question 5 Comment
		exclusive? EOP-001-2.1b Attachment 1 says "12. Requests of government - Requests to appropriate government agencies to implement programs to achieve necessary energy reductions." This seems to be a type of energy reduction which is covered in 2.2.7, therefore Dominion suggests removing 2.2.4.
SPP Standards Review Group	No	We agree with the intent of the SDT to create a separate requirement for Balancing Authorities to have an Emergency Operating Plan. Unfortunately, the requirement actually combines three requirements (development, maintenance and implementation) into a single requirement. We recommend splitting each of these into separate requirements. Additionally, the Time Horizon for development and maintenance of the Emergency Operating Plan is different than that for implementation. It may be more appropriate to include implementation of the Emergency Operating Plan to prevent or mitigate operating Emergencies within its Balancing Authority Area within R6. Also, the Violation Risk Factors for development and maintenance of the plan should be "Medium", while the Violation Risk Factor for implementation should be "High". Corresponding changes to M2 would need to be made to reflect these proposals. The measurement for implementation is also troubling as registered entities may be in the position of having to prove a negative if they do not have an Emergency during an audit period. Additionally, we request clarification on the intent of the term 'implement' in R2. Does this mean simply disseminating the Plan throughout your organization including providing it to your operators? Or does this mean activating your Plan when an Emergency occurs? If it's the former, then it fits this requirement and we would propose the SDT use 'disseminate' or 'issue' for the term. However, if it is the latter, then it doesn't belong in this requirement but perhaps in R6. It seems that the intent could be the latter since the SDT used implement again in Part 2.1 in conjunction with activate. The Emergency Operating Plan, specified in R2, should include the requirement to notify

Organization	Yes or No	Question 5 Comment
		the BA's RC of its current and projected System conditions. R6 would then simply require implementation of the plan. (See our comment in Question 11 below.)Part 2.3. is not clear. An emergency plan that includes procedures, processes and strategies, may not need to be revised for every change in the BA's Balancing Authority Area. The requirement does not include any periodic review. Is the intent of the SDT that the process include some periodic review or is that entirely up to the BA? As currently stated, the scope is entirely too broad.EOP-002-3.1 R5. which states "A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return Interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities." does not appear to be covered in R2 as indicated in the Mapping Document. This requirement should be included in this standard or included in the BAL standards in Project 2010-14.2 Periodic Review of BAL Standards. Delete the 'as' in the 2nd line of M2 between the 'have' and 'evidence'.
Florida Municipal Power Agency	No	Similar to comments on Question 2, if the RC is retained as an approval authority, then, the standard needs to better describe change management and what changes the RC is to review and approve.
Duke Energy	No	See Duke Energy comments on question 2. In addition we suggest the following rewording of R2.2,"Procedures, processes, or strategies to prepare for and mitigate Emergencies including a list for consideration, that addresses at a minimum:"
Southern Company: Southern Company Services, Inc.; Alabama Power	No	Southern does not believe all of the "minimum" set of elements outlined in R2.2 should be included for the BA. EOP-001-b R4 states, "Each

Organization	Yes or No	Question 5 Comment
Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan." Southern also believes verbiage from the current version that states that only applicable requirements for an entity are to be included in a Plan should also be stated in this revised requirement. Some of the areas of concern in R2.2 are: o R2.2.2 and R2.2.3: What is the difference between Voluntary Load reductions and Public appeals? o R2.2.4: What governmental programs is the SDT referring to? o R2.2.6: What customer fuel switching? Why is this part of a minimum required set of Plan content since it is our experience that this is not a widespread option for most entities? Southern recommends an additional requirement being added that requires the GOP to provide the data to the BA.
SERC OC Review Group	No	The OC Review Group is concerned with the phrase "At a minimum" as it is possible that certain elements may not be applicable to a certain TOP. It is recommended that the term "applicable" be utilized. Current R2 language: Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: Proposed R2 language: Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate capacity and Energy Emergencies. The Emergency Operating Plan shall include the applicable elements when developing its Emergency Operating Plan:
ACES Standards Collaborators	No	(1) As stated in early comments, we do not support the RC approval process because it is primarily an administrative function. (2) Has the drafting team considered the situation where an entity may have load in two different RC Areas? Would they need to have two separate plans and two separate approvals from each RC? What happens if there are three RCs? There are several entities in North America that operate in several regions. This

Organization	Yes or No	Question 5 Comment
		standard is proposing a highly complicated approval process that is unnecessary for reliability.
DTE Electric	No	The end of the first sentence “capacity and Energy Emergencies” should be “Capacity and Energy Emergencies” since Capacity Emergency and Energy Emergency are both defined terms in the NERC Glossary. EOP-001-2.1b Attachment 1 listed “Elements for Consideration in Development of Emergency Plans”. Since the BA only had to consider the elements, those that were not applicable did not need to be addressed in the plan. As written, EOP-011 R2 requires the BA to develop procedures, processes or strategies for items that would not apply to their BA area. Consider replacing “At a minimum, the Emergency Operating Plan shall include:” with “As applicable to the Balancing Authority, the Emergency Operating Plan shall include:”. To show compliance, the BA would respond in the RSAW that certain elements were considered but not applicable. This comment is complementary to the suggestion in comment 13 below regarding EEA levels. Consider adding 2.2.10: “The appropriate conditions under which NERC Energy Emergency Alerts are to be requested.”
ISO/RTO Standards Review Committee	No	We agree with the general intent of R2, but have the following comments: R2.2 requires the BA to develop procedures, processes or strategies to prepare for and mitigate emergencies. Thus, the actionable obligations under 2.2 are the development of procedures. Requirements 2.2.1-2.2.9 are intended to establish a non-exclusive list of means to address the emergencies for which the entity is to have related procedures/plans/strategies. With respect to R2.2.2-R2.2.9, the standard achieves its goal, because those requirements list ways / means to address the emergency, and then 2.2 requires the entity to have plans to utilize those means to mitigate the emergency. However, R2.2.1 does not accomplish this goal, because, as written it does not establish a means of addressing the emergency. Rather, it simply identifies characteristics of

Organization	Yes or No	Question 5 Comment
		generating units. In order to make sense under the standard, R2.2.1 needs to be revised to make it clear that the entity is to apply generating unit characteristics in some context for use in mitigating an emergency. For example, it could be revised as follows (add highlighted language):2.2.1. Appropriate utilization of generating resources in its Balancing Authority Area taking into consideration all relevant until characteristics, including, but not limited to, the following:2.2.1.1. capability and availability;2.2.1.2. fuel supply and inventory concerns;2.2.1.3. fuel switching capabilities;2.2.1.4. environmental constraints.In addition to the above context comment, we recommend the SDT discuss how this standard can be practically implemented, and consider whether the standard can actually achieve some of the underlying objectives. First, there are terms such as “extreme weather” and “coordinate” that are commonly used in the industry - but may not be precise enough in a mandatory requirement associated with compliance. There is no defined term of what extreme weather is and what may be considered extreme in one geographic location may not be extreme in another. For example, one would not expect a large metropolitan area in the South, to have a massive fleet of ice and snow removal equipment on stand-by to clear roads for a 1 in 100 year ice/snow storm. Such should also be considered for the electric industry. The SDT should have a clear way to communicate their expectations to the entities impacted by this standard on how to interpret for them what is an appropriate extreme event. In addition, there are numerous instances where entities are required to coordinate with other entities on emergency plans. However, there is no explanation of what constitutes appropriate coordination. Without guidance on how entities must coordinate, it will be difficult for entities to know the nature and degree of coordination necessary to meet such requirements. Lastly, there should not be an expectation that Transmission Operators, Balancing Authority and Reliability Coordinators will have authority over a Generator Operator’s

Organization	Yes or No	Question 5 Comment
		decisions to reserve its fuel supplies to meet plans developed by the Balancing Authority in advance of any potential emergency conditions. Generators make economic decisions on what and how much fuel to burn. We do not interpret this standard as having any mandatory requirement for any entity to determine when they will or will not run their units to preserve any particular fuel source. On the other hand, if the expectation is that a BA needs to have an Emergency Operating Plan to mitigate resource constraints under insufficient fuel supply situation, then the only option is rotational load shedding during a prolonged period of fuel supply deficiency after all other measures have been exhausted. a. The intent of and linkage between R2, Part 2.2, its sub-parts 2.2.1 and those parts listed under 2.2.1 are unclear. The last sentence in R2 says: "At a minimum, the Emergency Operating Plan shall include:2.2. Procedures, processes or strategies to prepare for and mitigate Emergencies including, at a minimum:2.2.1 Generating resources in its Balancing Authority Area 2.2.1.1 Capacity and availability It is unclear on what's expected from 2.2 when it asks for procedures, etc. to prepare for and mitigate Emergencies, then 2.2.1 starts off by saying "Generating resources..." Does it mean having procedures, etc. to mitigate Emergencies caused by generating resource deficiency? The whole R2 and its parts need to be worded to provide clarity. b. All the parts under Part 2.2.1 are unclear as to what it is that the BA is supposed to guard against. For example, is the BA supposed to prevent the generating resource shortage caused by fuel supply and inventory concern (Part 2.2.1.2) or by environmental constraints (Part 2.2.1.4)? Under these conditions, we are unable to see how a BA can hope to have Emergency plans or procedures in place to mitigate prolonged resource shortage caused by these events, some of which are unpredictable and whose mitigation can be out of a BA's capability and control. If a BA is unable to mitigate the adverse impact, shedding firm load may well be the last resort. The standard needs to have this provision to ensure the BA does not

Organization	Yes or No	Question 5 Comment
		become liable for events that it did not cause or over which it had any control.
Florida Power & Light	No	This new requirement is too prescriptive, specifically requirement 2.2 where it defines minimum requirements a BA should include in the Emergency Operating Plan. Some of these requirements may not apply to all BAs.
Idaho Power Company	No	Some environmental constraints are required to comply with at all times. For these constraints, NERC cannot dictate their violation. Redispatch of generation should be a BA function.
Xcel Energy	No	R1 and R2 language is strict in that an entity's EOP "shall include" elements defined in R1.1 to R1.3 and R2.1 to R2.3 respectively. What will happen in a situation where one of those elements does not apply to an entity? This standard is implying that all the elements identified in R1.1 to R1.3 and R2.1 to R2.3 must be included in the EOP whether they are applicable or not. The current EOP-001 R4 allows for in its Attachment 1 to be omitted if they are not applicable ("shall include the applicable elements"). We feel like the new EOP-011 standard should include similar language to allow for this flexibility. Could the Standard Drafting Team respond why the language in EOP-011 R1 and R2 was written to be more restrictive than the current EOP-001 R4 and whether items in R1.1 to R1.3 or R2.1 to R2.3 could be omitted from an EOP if found to be not applicable to an entity? Additionally, In Requirement 2.2.4. it is unclear what "Governmental programs" is referring to. This term is not descriptive enough in this context to understand clearly what is being asked for. This appears to be a carry over from EOP-001 Attachment 1 Item 12 Requests of government which reads "Requests to appropriate government agencies to implement programs to achieve necessary energy reductions." If this is the case, we suggest that the language in R2.2.4 be modified to "Governmental

Organization	Yes or No	Question 5 Comment
		programs to reduce Load". Additionally, the word "develop" should be removed from the requirement. Every entity should have a plan today. It should be maintained and implemented. IF an entity does not have a plan, it will have to develop one to have one to implement. The requirement does not need to address this issue.
Wisconsin Electric	No	The RC should not be the approval authority for the BA emergency plan. Given the required minimal inclusions listed in the draft standard, it's not clear why an RC would need to approve or ensure any type of coordination. As an example, why would an RC have to approve a procedure, process, or strategy for conducting public appeals, government programs, or reduction of internal utility energy use? If an RC has specific points of necessary coordination, why not simply require the RC to develop the elements the entities in their RC area need to coordinate? Changing to the wording of 2.2.1.1 is required; currently it does not flow with 2.2.
City of Tallahassee	No	TAL does not understand the intent of R2.2.4 (Governmental programs) in an emergency context. As written, it appears the language suggests entities plan for emergencies with an expectation of assistance from government programs. It is our belief that our plan should accommodate the worst case scenario. Also, requiring the RC to approve the plan places an administrative burden on both the entity and the RC.
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Hydro One	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 5 Comment
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Pepco Holding Inc.	Yes	
Northeast Utilities	Yes	
Lincoln Electric System	Yes	
Bonneville Power Administration		BPA believes clarfication is needed so that a BA may reduce load either directly or through TOP as designed with regard to 2.28 and 2.27
Public Service Enterprise Group		As described in our response to question 17 that addresses changes to Alert Level 2, change 2.2.7 as follows: "Use of [STRIKE:Interruptible Load, curtailable Load and demand response][ADD controllable and dispatchable Demand Side Management Load];"
Consumers Energy Company		N/A to SC&M Department

6. **The EOP SDT has developed proposed Requirement R2, Part 2.2.8 as a process to include manual Load shedding plan coordination. Do you agree that Requirement R2, Part 2.2.8 clearly defines required performance? If not, please provide specific suggestions for improvement, including alternate language**

Summary Consideration: In Requirement R2 Part 2.4.8., the EOP SDT has added the term "Operator-Controlled" preceding the language "manual Load shedding," as it was in the currently-enforced standard, EOP-003-2 Requirement R8. The EOP SDT also agrees that the intent of UFLS is meant as all automatic Load shedding, including UVLS, if applicable; but to still largely maintain separate "plans" for manual and automatic Load shedding. It is the EOP SDT's intention that entities would strive to maintain an operator-controlled manual Load shedding plan that is largely separate and distinct from their automatic Load shed plans. The EOP SDT also understands that when, for example, localized Load shedding is needed, that it may need to include feeders that are part of any automatic Load shed system. Conversely, for Capacity Emergencies, if operator-controlled Load shedding is needed, it is desirable to avoid feeders with automatic Load shedding, such that automatic Load shedding functionality is maintained.

Organization	Yes or No	Question 6 Comment
MRO NERC Standards Review Forum	No	We believe that the "automatic Load shedding" is either UFLS or UVLS (and maybe an SPS/RAS). It is very hard to (and impossible) "coordinate" an automatic system with a manual system. Since R2.2.8 is an element of the Emergency Operating Plan, recommend R1.2.5 to read: Manual Load shedding plan(s) incorporated to minimize the use of automatic Load shedding;". This will allow the entity to have a preconceived (pre-planned) process for when the risk is higher that an automatic Load shedding may occur.
Dominion	No	Dominion is concerned that this could be read as requiring manual (human at station) load shed as opposed to automatic (SCADA) when we believe the intent is to coordinate so as to avoid overlap with UFLS and UVLS programs. We suggest 2.2.8 read as 'Operator controlled manual Load shedding plan coordinated to minimize the

Organization	Yes or No	Question 6 Comment
		use of UFLS and UVLS automatic Load shedding.' In which operator controlled manual load shedding was used in EOP-003-2.
SPP Standards Review Group	No	The phrase "coordinated to minimize the use of automatic Load shedding" in Requirement 2, Part 2.2.8 is not clear. Is the intent to coordinate the manual Load shedding plan with those locations that have automatic Load shedding installed so as not to duplicate the same Load in both manual and automatic plans? Or is the intent to develop a manual Load shedding plan that will be enacted quickly enough so that automatic Load shedding is minimized? If it is the former, we suggest revised language for Part 2.2.8.: "Manual Load shedding plan coordinated to minimize the use of locations with automatic Load shedding;". We may even go further to propose deleting the phrase "to minimize the use of automatic load shedding" entirely as this seems to be a bit of editorializing. If it is the latter, then the reason for having a manual Load shedding plan is immaterial in the standard. It definitely needs to be in your Emergency Operating Plan, just not in the standard.
Florida Municipal Power Agency	No	Similar to 1.2.5, the automatic load shedding to be coordinated with is UFLS, not UVLS; hence, the bullet should be made specific to the type of load shedding to be coordinated with. It is unrealistic to expect a coordination of load shedding between UFLS and UVLS, that is, in areas where both UVLS and UFLS is needed, there will be overlap of the distribution feeders, i.e., there will be individual feeders that will have both UFLS and UVLS on it.
Northeast Power Coordinating Council	No	Same comments as provided in Question 3 for Part 1.2.5 on the need to expand this part to more clearly stipulate who or which plans a BA needs to coordinate its manual load shedding plan with.
Duke Energy	No	See Duke Energy comments on question 3.
Southern Company: Southern Company Services, Inc.;	No	Southern does not agree that R2, Part 2.2.8 clearly defines required performance. Southern recommends that the SDT modify the rationale included in the standard or

Organization	Yes or No	Question 6 Comment
Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		the technical background and rationale document to clearly explain the intent of the requirement.
SERC OC Review Group	No	The OC Review Group recommends that adding "Operator controlled" further clarifies R2, Part 2.2.8Current language: 2.2.8. Manual Load shedding plan coordinated to minimize the use of automatic Load shedding; Proposed language: Operator controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding;
ACES Standards Collaborators	No	(1) We would like clarification on minimizing the use of automatic load shedding. Manual load shedding could be an operator pushing a button to initiate load shedding. We believe the standard is attempting to state that manual load shedding should be planned to minimize the use of UFLS or UVLS. However, the standard is not this specific and needs to be clarified. (2) We are concerned about the ambiguous term of coordination and the varying compliance monitoring approaches from regional entities. We would like to see compliance guidance or an RSAW to state how this will be evaluated.
ISO/RTO Standards Review Committee	No	Same comments on R1.2.5 under Q3 on the need to expand this part to more clearly stipulate with whom or which plans a BA needs to coordinate its manual load shedding plan.

Organization	Yes or No	Question 6 Comment
Florida Power & Light	No	Requirement not clear. Is this requirement intended to use the manual load shed to prevent automatic load shed or is it to ensure that the same resource is not used for manual and automatic load shed?
PacifiCorp	No	R2, Part 2.2.8 does not clearly define required performance. In the proposed requirement, the language 'coordinated to minimize the use of automatic Load shedding' does not provide sufficient guidance on the intended load shed policy. The Drafting Team should develop language which provides more specific guidance on how manual Load shedding should be coordinated, and provide a more specific performance measure than 'minimize the use' of automatic Load shedding. With respect to the latter, the Drafting Team may want to specifically reference minimizing dependence on under voltage and under frequency Load shedding plans if that is the intention.
Bonneville Power Administration	No	BPA believes this applies only if a BA has direct-control load shedding.
Hydro One	No	The Balancing Authority should gain documented approval from the Load Serving Entity as part of their coordination.
Idaho Power Company	No	This coordination may in fact require to shed load manually that was included in the Automatic Load Shedding plan. We believe the Balancing Authority should have adequate load shedding capability and capacity. As part of 2.2, it should just say "Processes for manual load shedding."
Xcel Energy	No	There is no defined performance because of the use of the word "minimize". Does this mean any use of automatic load shedding violates the standard? If so, entities should remove any automatic load shedding capability so they do not violate the standard. However, that will put the interconnection at greater risk, which is not the goal of the standards. As written, there is no clear measurement process. It would have to be argued on a case by case basis and an auditor/regulator can argue any

Organization	Yes or No	Question 6 Comment
		automatic load shedding violates the standard. This is a detail that cannot be properly addressed in a standard as the specifics will vary with each entity.
Independent Electricity System Operator	No	Same comments on R1.2.5 under Q3 on the need to expand this part to more clearly stipulate with whom or which plans a BA needs to coordinate its manual load shedding plan.
Public Service Enterprise Group	No	The requirement for a coordinated manual Load shedding plan is a good one. However, the BA should coordinate its plan with its LSEs, DPs, and their respective TOPs. TOPs should be added to the BA coordination because a manual Load shedding plan is also required in R1 for TOPs. The two entities (TOP and BA) should coordinate their manual Load shedding plans among themselves before submitting such plans to their RC for approval. Part 2.2.8 should therefore be modified as follows: "Manual Load shedding plan coordinated [ADD:among its Load Serving Entities and Distribution Providers and their respective Transmission Operator(s)] ...."
Tacoma Power	No	Tacoma Power is unsure if the intent is: a) for the System Operator to minimize manually shedding facilities that have automatic load shedding equipment installed in lieu of facilities that do not, -OR- b) to utilize manual load shedding (preemptively) to attempt to forestall automated load shedding from occurring.
Wisconsin Electric	No	It is not clear what or with whom coordination is required. The proposed standard "Rationale for R2" section indicates that TOP and BA load shedding "sometimes" needs to be coordinated. However, neither R1 (TOP requirement) nor R2 (BA requirement) explicitly require coordination between the two.
City of Tallahassee	No	TAL is confused by R2.2.8. Is the intent not to overlap manual and automatic (UFLS) load shed tools (i.e. feeder circuits) or is the intent to require manual load shedding prior to activation of automatic load shedding? The verbiage does not specify who must be part of the coordination effort.

Organization	Yes or No	Question 6 Comment
Lincoln Electric System	No	Refer to comment in Question #3.
Arizona Public Service Company	Yes	
DTE Electric	Yes	
Manitoba Hydro	Yes	
Pepco Holding Inc.	Yes	
Consumers Energy Company		N/A to SC&M Department

7. The EOP SDT has developed proposed Requirement R2, Part 2.2.8 without time measure. The currently-enforce EOP-003-2, Requirement R8 states, "… timeframe adequate for responding to the emergency." Do you support Requirement R2, Part 2.2.8 without a time measure? If not, please provide specific suggestions for improvement, including alternate language.

Summary Consideration: The EOP SDT agrees that the time frame may vary by the request of the Reliability Coordinator or Transmission Operator as a directive. If a directive cannot be performed in the time frame requested, the process (per TOP-001-1 and IRO-001 [as well as other standards]) is to report this information back to the Reliability Coordinator and Transmission Operator so further actions can be taken to mitigate the event. The Rationale for Requirement R2 addresses that an Emergency plan may sometimes require coordination between the Balancing Authority and the Transmission Operator. The EOP SDT held discussion to emphasize the importance of coordination between the Balancing Authority/Transmission Operator in any type of event pertaining to manual Load shed and in addressing how a directive should be handled, regardless of the content of the directive.

Organization	Yes or No	Question 7 Comment
SPP Standards Review Group	No	One of the issues identified in previous events has been that some entities have manual Load shedding plans that require dispatching personnel to dispersed locations to implement the plan. The standard should include a requirement that manual Load Shedding be able to be implemented in time to mitigate the Emergency. We suggest the requirement include that the Manual Load shedding plan be capable of being implemented by an operator remotely. This addresses the issue of not being able to respond quickly to a given situation while at the same time eliminating the ambiguity of maintaining the existing language in EOP-003-2, R8.
ACES Standards Collaborators	No	(1) We support manual firm load shedding without a specific time measure. However, we are concerned about the ambiguous term of coordination and the varying compliance monitoring approaches from regional entities. We would like to see compliance guidance or an RSAW to state how this will be evaluated. (2) Part 2.2.9 needs to be revised. The clause "if not covered by other elements of the plan" is confusing and does not need to be in a requirement. Either the BA needs to have a

Organization	Yes or No	Question 7 Comment
		strategy for extreme weather or not. This language only adds confusion and needs to be removed.
PacifiCorp	No	PacifiCorp supports use of language similar to EOP-003-2 R8 and the language "... timeframe adequate for responding to the emergency." PacifiCorp annually updates detailed analyses which produce block load shed plans and instructions. Operator training, combined with block load shed plans and instructions, ensures operators are capable of implementing load shedding in a timeframe adequate for responding to an emergency.
Idaho Power Company	No	An entity could lean on the interconnection for up to 30 minutes per the proposed BAL-001-2 as long as the interconnection was stable. BAL-002-1 says that the BA shall return its ACE to zero or the pre-disturbance point if ACE was negative within 15 minutes. This requirement needs to be more specific possibly using 30 minutes as in the proposed BAL-001-2.
Tacoma Power	No	The current EOP-003-2 R8 language "timeframe adequate for responding to the emergency" should remain. Load shedding plans that are not viable (i.e. the System Operator has no hope of actually executing the plan quickly enough to mitigate the emergency) are useless. I fear that without this measurement, plans that are not actually useful may be created.
Arizona Public Service Company	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern	Yes	Other standards adequately cover the time frame requirements.

Organization	Yes or No	Question 7 Comment
Company Generation; Southern Company Generation and Energy Marketing		
SERC OC Review Group	Yes	The SERC OC Review Group respectfully recommends that the SDT consider changing M2 to align with M1 by identifying the Reliability Coordinator as the approving entity. Current M2 language: Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R2. Proposed M2 language: Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2 that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability Coordinator; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R2.
Northeast Power Coordinating Council	Yes	Same comment as for Part 1.2.5 in the response to Question 4.
ISO/RTO Standards Review Committee	Yes	Same comment for Part 1.2.5 under Q4, above.
Xcel Energy	Yes	The time frame is determined by the emergency. The current language is impossible to fairly enforce. Therefore, it should be removed. We support the drafting team's position on this issue.
Independent Electricity System Operator	Yes	Same comment for Part 1.2.5 under Q4, above.

Organization	Yes or No	Question 7 Comment
Xcel Energy	Yes	The time frame is determined by the emergency. The current language is impossible to fairly enforce. Therefore, it should be removed. We support the drafting team's position on this issue.
Independent Electricity System Operator	Yes	Same comment for Part 1.2.5 under Q4, above.
Pepco Holding Inc.	Yes	Don't need to duplicate the same requirement in different Standards.
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Florida Municipal Power Agency	Yes	
Duke Energy	Yes	
DTE Electric	Yes	
Florida Power & Light	Yes	
Bonneville Power Administration	Yes	
Hydro One	Yes	
Public Service Enterprise Group	Yes	

Organization	Yes or No	Question 7 Comment
Manitoba Hydro	Yes	
Wisconsin Electric	Yes	
City of Tallahassee	Yes	
Consumers Energy Company		N/A to SC&M Department

8. The EOP SDT has developed a requirement to address a directive from Paragraph 548 of FERC Order No. 693. This directive states "…the Commission finds the reliability coordinator is a necessary entity under EOP-001-0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity." Requirement R3 requires the Reliability Coordinator to coordinate the Emergency Operating Plans of the entities in its Reliability Coordinator Area to provide a wide-area perspective and to ensure that they are compatible and support reliability in the Reliability Coordinator Area. This also relates to Requirement R3, Part 3.3 of EOP-001-2.1b, which requires coordination of plans. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language.

Summary Consideration: The EOP SDT has reviewed the comments below and, in coordination of the other comments received, has deleted Requirement R3. The EOP SDT has placed the requirement to coordinate plans on the Balancing Authority (Requirement R2 Part 2.5) and on the Transmission Operator (Requirement R1 Part 1.3). The following language was added to Requirement R1 Part 1.3, "Strategies for coordinating Emergency Operation Plans with impacted Transmission Operators and impacted Balancing Authorities." The following language was added to Requirement R2 Part 2.5, "Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators."

Organization	Yes or No	Question 8 Comment
SPP Standards Review Group	No	While we agree with the intent, the language of the proposed requirement R3 only requires coordination within the Reliability Coordinator Area. Especially for entities on the seams between Reliability Coordinator Areas, it is essential that these plans be coordinated with neighboring Reliability Coordinators. We propose the following language for R3: "Each Reliability Coordinator shall review the Emergency Operating Plans of the entities in its Reliability Coordinator Area and with neighboring Reliability Coordinators to ensure that the plans are compatible and support reliability of the Bulk Electric System." This proposal also eliminates potential issues with the use of the term 'coordinate'.

Organization	Yes or No	Question 8 Comment
Northeast Power Coordinating Council	No	We support the proposed requirement, and we agree with the intent of R3 and R4 (to have Emergency Operating Plans by the TOPs and BAs coordinated, and approved by the RC). However, we believe putting the coordination responsibility solely on the RC (as Requirement R3 suggests) is neither sufficient nor appropriate. The TOPs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other TOPs and BAs in the RC Area. Likewise, the BAs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other BAs and TOPs in the RC Area. The RC's role, then, will be to assess if such coordination occurred, and approve or disapprove the EOPs. We suggest R3 be revised to explicitly state the responsibilities for the TOPs and the BAs (or any other entities within the RC's Area) to coordinate their EOPs. Alternatively, a new requirement may be created to capture such responsibilities.
Duke Energy	No	Duke Energy suggests replacing "coordinate" with "review" in R3 as follows:" Each Reliability Coordinator shall review the Emergency Operating Plans of the entities in its Reliability Coordinator Area to ensure that the plans are compatible and support reliability in the Reliability Coordinator Area." This provides consistency with the language in R5 of EOP-006-2 where an RC reviews the Restoration plans to determine if they are compatible and support the Reliability of the RC Area.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	Southern does not agree that the Reliability Coordinator should be obligated to review/approve all TOP and BA Emergency Operating Plans. This requirement/standard places an administrative burden on Reliability Coordinators to review / approve numerous Emergency Operating Plans. Historically, RC approval has not been required and registered TOPs/BAs have implemented their emergency plans to mitigate the emergencies without negatively impacting neighboring TOPs/BAs, so it is not clear why RC approval is now required. Southern requests the SDT reconsider RC approval. If the requirement remains: o The term "coordinate" should be changed to "review" because "coordinate" implies a more active involvement in the development of the Operating Plans, including such items as facilitating

Organization	Yes or No	Question 8 Comment
		development meetings, etc. That would be required to merely review and approve/disapprove a Plan. o The SDT should more clearly, in the requirement itself or in the Rationale, describe what Plan parameters they feel should be evaluated for "compatibility" so that there will be consistency among the RC review activities.
ACES Standards Collaborators	No	Why not require the RC to post its emergency operating plans and notify all of the entities in its area of any changes? The TOP and BA could align their emergency plans with the RC and then the RC could review these plans for conflicts. The RC already is required to perform emergency operations training with other entities, so requiring an approval process is administrative and unnecessary.
Bonneville Power Administration	No	BPA believes this approval adds another layer to a wide area responsibility when the issue is mostly between smaller regions. The RC approval is not needed of 40 entities. The RC should direct load shedding through their own plan but they should have copies of the individual plans.
Xcel Energy	No	It is unclear how the RC will coordinate plans that will be addressing different issues and owned by different entities. Will the RC require that the entities only use a certain section of their plan if another entity is also experiencing an emergency at that time? While we support the intent of this requirement, it may need a guideline or other guidance document to help the process flow.
Wisconsin Electric	No	Without the RC identifying the points of coordination, it's not clear how they can "coordinate" between multiple BAs and TOPs. The standard requires the TOPs and BAs to address specific items in their plans and their plans to be approved by the RC. The timing of TOP/BA submission for RC approval will likely be sporadic and the standard requires the RC to provide approval or disapproval within 30 days. It's not practical for an RC to coordinate plans from multiple BAs or TOPs submitted at different times without the RC issuing some type of guidance that identifies points of coordination.

Organization	Yes or No	Question 8 Comment
Electric Reliability Council of Texas, Inc.	No	Requirement 3 requires the RC to coordinate the relevant plans to "ensure that the plans are compatible and support reliability in the Reliability Coordinator Area." The RC review cannot "ensure" reliability. Furthermore, reliability is undefined, and, therefore ambiguous in this context. The wording should be revised as follows (consistent with EOP-006-2 R5) to mitigate these issues:R3. Each Reliability Coordinator shall review the Emergency Operating Plans required by EOP-011 of the entities within its Reliability Coordinator Area. [Violation RiskFactor = Medium] [Time Horizon = Operations Planning]R3.1. The Reliability Coordinator shall determine whether the entity's Emergency Operating Plan is coordinated and compatible with the Reliability Coordinator's Emergency Operating Plan and other entity's within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with stated reasons, entity's Emergency Operating Plan within 30 calendar days following the receipt of the entity's Emergency Operating Plan. In addition to the RC, TOPs should be required to coordinate their plans with other TOPs and BAs in the RC Area. Similarly, BAs should also be required to coordinate their plans with other BAs and TOPs in the RC area. Load shed plans, or other transmission emergencies may require coordination at the TOP level for switching and other similar actions. The RC may not have that detailed visibility or have a role in switching instructions or types of load, critical loads, etc. that the TOP manages. Another important example is load shedding coordination - manual/automatic load shed coordination involves TOP to TOP coordination. For these reasons TOs and BAs should have a coordination role - limiting coordination to just the RC is inappropriate. The revised standard does not include the Communication Protocols from EOP 001 R4.1. While specific communication protocols related to prevention of miscommunications is addressed in the COM standards, it is important that appropriate communications take place between the appropriate entities during emergency operations to support adequate situation awareness for all relevant entities. The EOP standards can facilitate this by making sure all relevant functional entities are identified for issuing and receiving the relevant notices/communications. While the standard does establish relationships between RC, BA, TOP's; DPs and GOPs are not implicated, and it is arguable that

Organization	Yes or No	Question 8 Comment
		these entities should have appropriate situational awareness during emergency operations. For example, after the RC notifies the BA, and TOP, likewise the BA and TOP should notify affected DPs and GOPs of the particular emergency. This promotes situational awareness. Additionally while DPs and GOPs play a lesser role, consideration should be given to their inclusion at appropriate levels. DPs should have emergency plans for those emergency actions they need to take, i.e. load shed voltage reduction. GOPs have a role to play and are more appropriate for addressing fuel supply and inventory, fuel switching capabilities, environmental constraints, reduction of internal usage, and most importantly WEATHERIZATION of units. At a minimum, they need to provide this information to the BAs. This is especially true in organized market regions (i.e. ISOs/RTOs). Including DPs and GOPs as appropriate is consistent with their applicability in other standards, such as the communication standards.
ISO/RTO Standards Review Committee	Yes	We support the proposed requirement, and we agree with the intent of R3 and R4 (i.e., to have Emergency Operating Plans by the TOPs and BAs coordinated, and approved by the RC). However, we believe that putting the coordination responsibility solely on the RC (as Requirement R3 so suggests) is neither sufficient nor appropriate. The TOPs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other TOPs and BAs in the RC Area. Likewise, the BAs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other BAs and TOPs in the RC Area. The RC's role, then, will be to assess if such coordination occurred, and approve or disapprove the EOPs. We suggest R3 be revised to explicitly state the responsibilities for the TOPs and the BAs (or any other entities within the RC's Area) to coordinate their EOPs. Alternatively, a new requirement may be created to capture such responsibilities.
Independent Electricity System Operator	Yes	We support the proposed requirement, and we agree with the intent of R3 and R4 (to have Emergency Operating Plans by the TOPs and BAs coordinated, and approved by the RC). However, we believe putting the coordination responsibility solely to the RC (as Requirement R3 so suggests) is not sufficient or appropriate. The TOPs themselves

Organization	Yes or No	Question 8 Comment
		should be responsible for coordinating their Emergency Operating Plans (EOPs) with other TOPs and BAs in the RC Area. Likewise, the BAs themselves should be responsible for coordinating their Emergency Operating Plans (EOPs) with other BAs and TOPs in the RC Area. The RC's role, then, will be to assess if such coordination occurred, and approve or disapprove the EOPs. We suggest R3 be revised to explicitly state the responsibilities for the TOPs and the BAs (or any other entities within the RC's Area) to coordinate their EOPs. Alternatively, a new requirement may be created to capture such responsibilities.
CenterPoint Energy	Yes	CenterPoint Energy agrees with the proposed coordination role for the Reliability Coordinator.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Florida Municipal Power Agency	Yes	
SERC OC Review Group	Yes	
DTE Electric	Yes	
Florida Power & Light	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 8 Comment
American Electric Power	Yes	
Hydro One	Yes	
Idaho Power Company	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Consumers Energy Company	Yes	
American Transmission Company, LLC	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	
Lincoln Electric System	Yes	
City of Austin dba Austin Energy	Yes	
ReliabilityFirst		ReliabilityFirst offers the following comments for consideration:1. Requirement R3 - ReliabilityFirst believes the intent of Requirement R3 (specifically the term “coordinate”) is ambiguous and will lead to potential interpretation problems. ReliabilityFirst believes this “coordination” is actually addressed in Requirement R4 in

Organization	Yes or No	Question 8 Comment
		which the Reliability Coordinators will be reviewing all Emergency Operating Plans and approving/disapproving them accordingly if there are any “coordination” type issues. ReliabilityFirst recommends removing Requirement R3 from the draft standard.

9. In addition to Requirement R3, the EOP SDT proposes an additional requirement, Requirement R4, applicable to the Reliability Coordinator to address the Order No. 693, Paragraph 548 directive. The proposed Requirement R4 requires the Reliability Coordinator to approve or disapprove Transmission Operator and Balancing Authority Emergency Operating Plans within 30 days of submittal. Since these Emergency Operating Plans are submitted on an agreed-upon schedule, the EOP SDT believes that 30 days is adequate time for the Reliability Coordinator to assess the plans. Do you support the proposed changes? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: The EOP SDT found that most commenters agreed with the 30-day time frame for the Reliability Coordinator to approve or disapprove Emergency Operating Plans. There were several questions raised as to the process if the plan is not approved by the Reliability Coordinator. The EOP SDT's intent is that the implementation window will allow time for the Balancing Authority's or Transmission Operator's plan(s) to initially be approved. Further, the EOP SDT's intent is that the Balancing Authority's or Transmission Operator's current Reliability Coordinator-approved Emergency Operating Plan would remain in effect until the revised plan gets approved. There were a few comments disagreeing with Reliability Coordinator approval of Balancing Authority and Transmission Operator Emergency Operating Plan(s). The FERC directive in Paragraph 548 of Order 693 mandates that the Reliability Coordinator be included as an applicable entity; while not specifically mandated that this meant plan approval by the Reliability Coordinator, the EOP SDT still feels approval by the Reliability Coordinator reduces risk to reliability.

Organization	Yes or No	Question 9 Comment
SPP Standards Review Group	No	While we support the concept of the requirement, we propose a rewording to improve clarity. We suggest: "Each Reliability Coordinator shall approve, or disapprove with stated reasons for disapproval, Emergency Operating Plans submitted by Transmission Operators and Balancing Authorities within 30-calendar days of submittal." M4 would need to be modified to parallel this language. Additionally, the question refers to an 'agreed-upon schedule' for submittal of the plans. We cannot find a reference to this agreement in the standard. Plans will need to be revised and then subsequently submitted for review and approval but there is nothing mentioned about an agreed-upon schedule between the Reliability

Organization	Yes or No	Question 9 Comment
		Coordinator and the Balancing Authority or Transmission Operator. Perhaps the SDT should look at the language contained in EOP-005-2 outlining timing for the submittal and approval of restoration plans by the Transmission Operator and Reliability Coordinator, respectively, for parallels for submitting and approval of Emergency Operating Plans.
Northeast Power Coordinating Council	No	It is not clear what an entity should do if its plan is not approved, especially if an entity is revising its plan to address a known deficiency or required changes to its existing plan. In this circumstance simply using the existing plan does not seem appropriate. We agree with the proposed R4, on the assumption that coordination between TOPs/BAs have occurred prior to the submittal of the individual EOPs. Please refer to our comments to Question 8.
ACES Standards Collaborators	No	(1) Does the drafting team really think that 30 days is sufficient amount of time to review potentially dozens of plans? What if they were all submitted during peak season? What is more important to reliability - reviewing documentation or the actual operation of the Bulk Electric System? The timeframes are administrative in nature and a burden on all entities that would have to comply. We strongly urge the drafting team to consider a different approach.
PacifiCorp	No	While PacifiCorp agrees with the RC having a 30 day period to review a TOP or BA Emergency Operating Plan, it appears that an applicable entity could be out of compliance either during the RC's review, or if the RC withholds approval until certain modifications to the Emergency Operating Plan are completed. The language in R1 and R2 require that a TOP or BA have a "Reliability Coordinator-approved" Emergency Operating Plan, providing no room for interpretation if the RC fails to meet its deadline or additional

Organization	Yes or No	Question 9 Comment
		coordination between neighboring entities is required. This puts a TOP or BA at risk that the RC will reject the Emergency Operating Plan simply to meet its deadline and maintain compliance with R4. The EOP SDT should revise R4 to allow the Reliability Coordinator to either: (1) approve; (2) approve pending modification; (3) or reject a proposed Emergency Operating Plan. This modification will address any issues that may arise out of either the Reliability Coordinator's ability to complete its review in the 30 day review period, and allow an opportunity for the Reliability Coordinator to coordinate between neighboring TOPs and BAs.
American Electric Power	No	In the FERC Order No. 693, Paragraph 632 (EOP-006-1), FERC has clearly directed that the Reliability Coordinator be involved in the development and approval of restoration plans. However, FERC did not make this distinction that the Reliability Coordinator approve the EOP (EOP-001-0) plans (Paragraph 547).Rather than what is currently proposed, the RC needs to be involved in the development and coordination of Emergency Operating Plans as opposed to approving those plans.
Idaho Power Company	No	Agree that the plans should be coordinated but I do not believe that the RC should formally approve the plan. If by approval the RC is saying they have performed R3 "Each Reliability Coordinator shall coordinate the Emergency Operating Plans of the entities in its Reliability Coordinator Area to ensure that the plans are compatible and support reliability in the Reliability Coordinator Area" and not found any incompatibilities or reliability concerns.
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration:Requirement R4 - ReliabilityFirst believes if the Reliability Coordinator disapproves an Emergency Operating Plan not only should they be required to state the reasons, they should also be required to provide specific recommended modifications that would lead to the Plan's

Organization	Yes or No	Question 9 Comment
		approval. ReliabilityFirst recommends the following for consideration "Each Reliability Coordinator shall approve or disapprove, with stated reasons for disapproval [and recommended modifications that would lead to the Plan's approval], Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans within 30 calendar days of submittal."
CenterPoint Energy	No	As stated above in response to Question 2, CenterPoint Energy does not agree with the proposed change to require Reliability Coordinator approval of Transmission Operator's Emergency Operating Plans. Paragraph 548 of Order 693 directed the ERO to 1) include the RC as an applicable entity, and 2) consider SoCal Edison's suggestion. The SoCal Edison comment in Paragraph 546 states that NERC "should receive input from stakeholders on which requirements should be exclusive to the transmission operator or balancing authority with the reliability coordinator responsible only for collecting and incorporating this information into its overarching plan". CenterPoint Energy reading of the directive is that it does not contain the addition of Reliability Coordinator approval and requiring such approval was specifically omitted by the Commission. Therefore, CenterPoint Energy believes this is an unnecessary expansion of FERC's directive in Paragraph 548. CenterPoint Energy strongly recommends Requirement R4 be deleted from the draft standard EOP-011-1.
City of Tallahassee	No	Requiring RC approval will add an administrative burden on each side. If approval is the end result, TAL recommends combining R4 with R3 to make one requirement requiring coordination and approval or disapproval. Recommend 60 days for approval. Although the submittal is on an approved schedule the "RC" is not a single person, but rather a committee. Work products often need to go through a formal committee process to gain "approval". 60 days minimizes the burden.

Organization	Yes or No	Question 9 Comment
City of Austin dba Austin Energy	No	City of Austin dba Austin Energy (AE) believes the RC can coordinate plans without having to approve them.
Dominion	Yes	Dominion believes the SDT is assuming the 'plans are submitted on an agreed-upon schedule', there is nothing in the standard that requires this, but we agree 30 days is adequate.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	If R3 remains, the 30 day review time is appropriate but that the 30 day time period should be prior to any implementation date specified in the BA/TOP Operating Plan. As was acknowledged by FERC in its Order for EOP-006, approval of these plans does not guarantee that they will adequately mitigate an Emergency for a BA/TOP but merely that the plans are compatible and support reliability. This concept needs to be captured in the requirement.
ISO/RTO Standards Review Committee	Yes	We agree with the proposed R4, assuming that coordination between TOPs and BAs has occurred prior to the submittal of the individual EOPs. Please refer to our comments/suggestions under Q8, above.
Independent Electricity System Operator	Yes	We agree the proposed R4, on the assumption that coordination between TOPs/BAs have occurred prior to the submittal of the individual EOPs. Please refer to our comments/suggestions under Q8, above.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Florida Municipal Power Agency	Yes	
Duke Energy	Yes	

Organization	Yes or No	Question 9 Comment
SERC OC Review Group	Yes	
DTE Electric	Yes	
Florida Power & Light	Yes	
Bonneville Power Administration	Yes	
Hydro One	Yes	
Xcel Energy	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Consumers Energy Company	Yes	
American Transmission Company, LLC	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
Lincoln Electric System	Yes	

10. The EOP SDT has developed proposed Requirement R5 to have a Transmission Operator that is experiencing an operating Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. This is a corollary requirement to existing EOP-002-3.1, Requirement R3; whereby the Balancing Authority performs a similar notification for its Emergencies. Do you support the proposed Requirement R5? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: The EOP SDT has discussed the comments received and agrees with the commenters that this requirement is parallel to TOP-001-1a and has deleted Requirement R5 from proposed EOP-011-1. The language, "Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an Operating Emergency," has been added to Requirement R1 Part 1.2.1.

Organization	Yes or No	Question 10 Comment
SPP Standards Review Group	No	It may be appropriate to include implementation of the Emergency Operating Plan to prevent or mitigate operating Emergencies on its Transmission System within R5. The Emergency Operating Plan, required in R1, should include the requirement to notify the Transmission Operator's Reliability Coordinator of its current and projected System conditions. R5 would then simply require implementation of the plan. (See our comments on Question 2.)We recommend the following for R5: "Each Transmission Operator that is experiencing an operating Emergency on its Transmission System shall implement its Emergency Operating Plan. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]"
ACES Standards Collaborators	No	We do not support the requirement as written. Why can't this notification requirement be included in the emergency operating specified in R1? This would eliminate the need for this requirement.

Organization	Yes or No	Question 10 Comment
American Electric Power	No	AEP believes R5 violates Paragraph 81 Criteria B7, as it is redundant with similar requirements in TOP-001-1a R5. The SDT needs to review the existing standards landscape for additional, potential redundancy.
City of Garland	No	Concern - TOP Operators have full authority and responsibility to deal with emergencies. Also, it is second nature for the operator to notify the RC as soon as he or she is able. Because an emergency is an "emergency", 1) the operator may be fully occupied dealing with the emergency in real time, 2) may not know the initiating factor that started the emergency until technical personnel (IT, substation, engineering, etc.) investigate, and 3) may not know or be able to "project system conditions". The concern is that an auditor could say, I listened to the phone recordings, I heard you notify the RC of the current conditions as you knew them but I did not hear you give any projections of return to normal or the system will be in this or that condition in 2 hours or etc. - you are therefore in violation of R5. Recommendation - end the sentence with "communicate the Emergency and the current status." The RC should have full visibility of the system and see outaged or overloaded elements. If the RC needs additional information beyond what is given, he can question the TOP Operator.
Tacoma Power	No	Tacoma Power would suggest the following modification: ...operating Emergency to communicate "as soon as practical" its Emergency...
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration: Requirement R5 - ReliabilityFirst believes there should be a timeframe associated with how long the Transmission Operator has to communicate the Emergency and its current and projected System conditions to its Reliability Coordinator. In a hypothetical situation, without a timeframe associated with the requirement, a Transmission Operator can communicate the Emergency 10 hours after the fact and still be compliant. ReliabilityFirst does not believe this meets the reliability intent of the requirement. ReliabilityFirst recommends the following for consideration: "Each Transmission

Organization	Yes or No	Question 10 Comment
		Operator that is experiencing an operating Emergency on its Transmission System shall communicate the Emergency and its current and projected System conditions to its Reliability Coordinator [within 30 minutes of the start of the Emergency].
CenterPoint Energy	No	CenterPoint Energy does not believe it is necessary to create a corollary requirement to EOP-002-3.1 R3. Such corollary requirements already exist in standard TOP-001-1a R5 and R8. TOP-001-1a R5 requires the TOP to inform its RC of emergency conditions and to mitigate the emergency if possible, while TOP-001-1a R8 requires the TOP to request emergency assistance from the RC if the TOP is unable to recover on its own. CenterPoint Energy believes the necessary communication between a TOP and its RC to ensure reliability during an Emergency is already mandated. The Company believes the proposed Requirement R5 is redundant based on P81 criteria and should be deleted from the draft standard EOP-011-1.
City of Austin dba Austin Energy	No	City of Austin dba Austin Energy (AE) finds the phrase “projected System conditions” unclear. AE prefers the TOP requirement be limited to “current System conditions” which is more aligned with the information a System Operator will have in real-time.
Florida Municipal Power Agency	Yes	The only other issue that may be appropriate to address is timing of the required communication. Maybe something like "as soon as reasonable while not unduly impacting response to the Emergency".
Northeast Power Coordinating Council	Yes	We support the addition of R5 to have a Transmission Operator that is experiencing an operating Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. (Clarification is needed for “projected system conditions.” A definition of this term would help clarify the intent of this statement so that it would not be open ended.)A responsible entity must communicate this to other TOPs and/or BAs that may be impacted by the TOP’s Emergency. How quickly does a TOP that is experiencing an operating Emergency

Organization	Yes or No	Question 10 Comment
		have to "communicate the Emergency and its current and projected System conditions to its Reliability Coordinator"?
ISO/RTO Standards Review Committee	Yes	We support the addition of R5 to have a Transmission Operator that is experiencing an Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. We are indifferent as to who should be responsible for communicating the Emergency to other TOPs and/or BAs that may be impacted by it, as long as this is performed by a responsible entity.
Independent Electricity System Operator	Yes	We support the addition of R5 to have a Transmission Operator that is experiencing an operating Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. We are indifferent as to who should be responsible for communication this to other TOPs and/or BAs that may be impacted by the TOP's Emergency, for so long as this is performed by a responsible entity.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Duke Energy	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi	Yes	

Organization	Yes or No	Question 10 Comment
Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
SERC OC Review Group	Yes	
DTE Electric	Yes	
Florida Power & Light	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
Hydro One	Yes	
Idaho Power Company	Yes	
Xcel Energy	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
Consumers Energy Company	Yes	

Organization	Yes or No	Question 10 Comment
American Transmission Company, LLC	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	
Northeast Utilities	Yes	
Lincoln Electric System	Yes	
Oncor Electric Delivery Company LLC	Yes	

11. The EOP SDT has developed proposed Requirement R6 to have a Balancing Authority that is experiencing a capacity or Energy Emergency to communicate its Emergency, current and projected system conditions to its Reliability Coordinator. This is a revision to existing EOP-002-3.1, Requirement R3. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: The EOP SDT agrees with the comments received to add the notification requirement within Requirement R2. The EOP SDT added the language, "Notification to the Reliability Coordinator, to include current and forecasted conditions, when experiencing a Capacity Emergency or Energy Emergency," to Requirement R2 Part 2.2., and deleted Requirement R6 from EOP-011-1.

Organization	Yes or No	Question 11 Comment
SPP Standards Review Group	No	It may be appropriate to include implementation of the Emergency Operating Plan to prevent or mitigate operating Emergencies within its Balancing Authority Area within R6. The Emergency Operating Plan, required in R2, should include the requirement to notify the Balancing Authority's Reliability Coordinator of its current and projected System conditions. R6 would then simply require implementation of the plan. (See our comments on Question 5.)We recommend the following for R6: "Each Balancing Authority Operator that is experiencing an operating Emergency within its Balancing Authority Area shall implement its Emergency Operating Plan. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]"
ACES Standards Collaborators	No	We do not support the requirement as written. Why can't this notification requirement be included in the emergency operating specified in R2? This would eliminate the need for this requirement.
DTE Electric	No	The end of the first sentence "capacity or Energy Emergencies" should be "Capacity or Energy Emergencies" since Capacity Emergency and Energy Emergency are both defined terms in the NERC Glossary.

Organization	Yes or No	Question 11 Comment
Xcel Energy	No	In the current EOP standards, a Load-Serving Entity can as for an EEA from the RC. As written, the LSE is not mentioned. Is the SDT therefore assuming that the BA must provide service to all loads within its area under its emergency plan regardless of generator ownership or load service responsibility?
Tacoma Power	No	Tacoma Power would suggest the following modification: ...Energy Emergency to communicate "as soon as practical" its Emergency...
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration: 1. Requirement R6 - ReliabilityFirst has similar concerns with Requirement R6 as stated in the comment to Requirement R5. Also, since Requirement R5 and Requirement R6 are very similar, ReliabilityFirst recommends combining Requirement R5 and Requirement R6 and having them applicable to both the Transmission Operator and Balancing Authority
Florida Municipal Power Agency	Yes	See comments to question 10.
Northeast Power Coordinating Council	Yes	We are indifferent as to who should be responsible for communicating this to other TOPs and/or BAs that may be impacted by the TOP's Emergency, as long as this is performed by a responsible entity.
ISO/RTO Standards Review Committee	Yes	We are indifferent as to who should be responsible for communicating the capacity Emergency or Energy Emergency to other TOPs and/or BAs that may be impacted by the TOP's capacity or Energy Emergency, as long as this is performed by a responsible entity.
Independent Electricity System Operator	Yes	We are indifferent as to who should be responsible for communication this to other TOPs and/or BAs that may be impacted by the TOP's Emergency, for so long as this is performed by a responsible entity.

Organization	Yes or No	Question 11 Comment
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Duke Energy	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
SERC OC Review Group	Yes	
Florida Power & Light	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
Hydro One	Yes	

Organization	Yes or No	Question 11 Comment
Idaho Power Company	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	
Lincoln Electric System	Yes	
Consumers Energy Company		N/A to SC&M Department

12. The EOP SDT has developed proposed Requirement R7 to have a Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator to notify, as soon as practicable, impacted Reliability Coordinators, Balancing Authorities and Transmission Operators. This is a revision to existing EOP-002-3.1, Requirement R3. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: The EOP SDT drafted the language "as soon as practicable" to provide some priority to the notification from the Reliability Coordinator, but not to have this requirement exceed the priority of mitigating the emergency itself. Based on comments received, the EOP SDT has changed the word "practicable" to "practical."

Organization	Yes or No	Question 12 Comment
SPP Standards Review Group	No	We recommend including the Load Serving Entity in this requirement as follows: "Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator, Balancing Authority or Load Serving Entity shall notify, as soon as practicable, impacted Reliability Coordinators, Balancing Authorities and Transmission Operators." We feel this is justified based on the statement in the first paragraph of the Introduction of Attachment 1, where the SDT points out that the Reliability Coordinator is responsible for communicating the 'condition' of Balancing Authorities or Load Serving Entities. However, the requirement doesn't include LSE. They need to be included. Additionally, we have some concern with the use of 'as soon as practicable'. We understand that this was inserted to stress the timeliness of this notification but have issues with its measurability. Some standards have used 'without intentional delay' in the past. While not a clear cut remedy, it does appear to be a little better and is consistent with other standards.
Northeast Power Coordinating Council	No	There should be a maximum time by which the RC must notify impacted parties; it cannot be left stated "as soon as practicable". Holding the RC responsible for this communication can be more streamlined and coordinated, but it adds time to

Organization	Yes or No	Question 12 Comment
		completion of the communication. Holding the individual entities whose area is experiencing an Emergency responsible for such notifications can speed up information dissemination, but may cause confusion. It must considered that an individual entity's top priority should be to resolve the Emergency.
Duke Energy	No	Duke Energy suggests the following revision to R7:"Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as practicable, neighboring Reliability Coordinators and those Balancing Authorities and Transmission Operators within its Reliability Coordinator Area." We believe this change is necessary because the use of the word "impacted" is broad and subject to interpretation by an auditor. However, the RC should be required to notify neighboring RCs who can notify those BAs and TOPs within its RC area for determination on the impacts the Emergency could have on their respective systems. By notifying the TOPs and BAs within its RC area, it provides the situational awareness necessary to protect the reliability of the BES.
SERC OC Review Group	No	The SERC OC Regroup respectfully requests further guidance and clarification on the term "impacted". The concern centers on which entities would be considered "impacted". Current R7 language: Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as practicable, impacted Reliability Coordinators, Balancing Authorities and Transmission Operators.
ACES Standards Collaborators	No	We request that the drafting team remove the language "as soon as practicable" from R7. This is ambiguous language, which cannot be measured and will only lead to confusion. We suggest replacing this clause with the word "other," so the requirement will state "...notify other impacted RCs, BAs, and TOPs." Otherwise, the requirement will literally require the RC to also notify the BA or TOP that just notified it.

Organization	Yes or No	Question 12 Comment
Hydro One	No	There should be a maximum time by which the RC must notify impacted parties; it cannot be left stating "as soon as practicable".
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration:1. Requirement R7 - ReliabilityFirst believes the term "as soon as practicable" is ambiguous, does not provide any added value, and should not be used in standards. This term leaves the requirement open to interpretation and potential problems in compliance monitoring and enforcement. ReliabilityFirst recommends the following for consideration "Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify the impacted Reliability Coordinators, Balancing Authorities and Transmission Operators[, within 30 minutes of the start of the Emergency.]"
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	Southern would like to see more guidance on determining what "impacted" means since it can be a subjective term and therefore makes the requirement less measureable.
ISO/RTO Standards Review Committee	Yes	We are indifferent as to who should be responsible for providing notification of an Emergency from a TOP or BA within a RC Area to those entities that are impacted or could be impacted, as long as this is performed by a responsible entity. In deciding who should be responsible, the SDT should consider that, while holding the RC responsible for this notification is more streamlined and coordinated, it requires additional time to complete the notification. On the other hand, holding the

Organization	Yes or No	Question 12 Comment
		individual entity whose area is experiencing an Emergency responsible for such notifications can speed up information dissemination, but may lack information that could have been included in a report provided by an RC, with its oversight and wider-area view.
Independent Electricity System Operator	Yes	We are indifferent as to who should be responsible for communication Emergency in a TOP or BA within a RC Area to those entities that are impacted or could be impacted, for so long as this is performed by a responsible entity. Holding the RC responsible for this communication is more streamlined and coordinated, but it adds time to complete the communication. Holding the individual entities whose area is experiencing Emergency can speed up information dissemination, but may cause confusions.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Florida Municipal Power Agency	Yes	
DTE Electric	Yes	
Florida Power & Light	Yes	
PacifiCorp	Yes	

Organization	Yes or No	Question 12 Comment
Bonneville Power Administration	Yes	
Idaho Power Company	Yes	
Public Service Enterprise Group	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Consumers Energy Company	Yes	
American Transmission Company, LLC	Yes	
CenterPoint Energy	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	
Lincoln Electric System	Yes	
City of Austin dba Austin Energy	Yes	

13. **The EOP SDT has revised EOP-002-3.1, Requirement R6, Part 6.5 and Requirement R7, Part 7.2 and included it in EOP-011-1 as Requirement R8. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language**

Summary Consideration: The EOP SDT intentionally added the Attachment 1 to the EOP-011-1 by its inclusion into Requirement R2 Part 2.3. and Requirement R5; making Attachment 1 applicable to Reliability Coordinator's and Balancing Authorities, but not Transmission Operators. The EOP SDT has been working in a collaborative effort with the BAL SDT, but in no way was it ever the intention of the EOP SDT to allow the Balancing Authority to not meet its CPS and DCS requirements.

Organization	Yes or No	Question 13 Comment
MRO NERC Standards Review Forum	No	R8 is based on the entity having time to perform the steps in the Emergency Operating Plan. As we know system conditions can change so fast that the entity's involved may have to skip steps in their plan to mitigate the emergency. Recommend R8 to read; The BA shall request its RC to declare a NERC EEA after the BA has EITHER performed the steps in its Emergency Operating Plan OR is unable to resolve the capacity or Energy Emergency condition.
Dominion	No	Dominion believes R8 should be included as a sub-requirement in R2, we do not believe it qualifies as a standalone requirement.
SPP Standards Review Group	No	Although we agree with the concept, the language of Requirement R8 implies that the Balancing Authority only requests an EEA after it has completed the steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. Coordination between the Plan and Attachment 1 is an issue. EEA Alert 1 is to be issued when the Energy Deficient Entity foresees the need to declare an Energy Emergency.

Organization	Yes or No	Question 13 Comment
		Alert 2 is issued when all available resources are in use. Alert 3 is issued when load management procedures are in effect. Alert 4 is issued when firm Load interruption is imminent or in progress. If an entity must first complete the steps in its Emergency Operating Plan (which must include manual Load shedding per R2) and is unable to resolve the capacity or Energy Emergency condition, the first three Alert Levels would have already been past. We suggest incorporating a new Part under Requirement R2.2 that requires the Balancing Authority requesting its Reliability Coordinator to declare Emergency Alert Levels satisfy the criteria for issuing an Energy Emergency Alert as outlined in Attachment 1. There are different Energy Emergency Alert Levels and they are issued at various stages within the event. The Balancing Authority's Emergency Operating Plan should include requesting the Reliability Coordinator to declare each level when conditions have been met for each level. This would eliminate the need for Requirement R8 and yet provide for the notification of the Reliability Coordinator and other impacted entities of the Emergency condition. The new Part 2.3.0 would read: "Utilization of Energy Emergency Alerts as detailed in Attachment 1." R8 could then be deleted.
Duke Energy	No	Duke Energy believes the proposed language for R8 could be interpreted to mean that all the steps in the entity's Emergency Operating Plan have to be performed before requesting the RC to declare an EEA. Our belief is that the entity's plan should include the steps taken for each EEA level that leads up to the entity making a determination to declare an EEA by making a request to the RC. We propose the following language for R8:"R8. Each Balancing Authority shall request its Reliability Coordinator to declare the appropriate NERC Energy Emergency Alert level, according to the Balancing Authority's Emergency Operating Plan, when the Balancing Authority is unable to resolve the potential or actual capacity or Energy Emergency condition. "We believe the proposed modification clarifies that not all the

Organization	Yes or No	Question 13 Comment
		steps in an entity's Emergency Operating Plan has to be performed before declaring and EEA.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	There is no progressive severity associated with the words in R8 that reflect the multiple levels of an energy emergency condition outlined in Attachment 1. As written R8 seems to indicate that an Energy Emergency Alert is not initiated until all steps of an Emergency Operating Plan are exhausted. Southern also believes that the SDT, either in the Requirement or Attachment, should take the opportunity to clarify that it is not necessary to explicitly call for manual load shedding to return ACE to zero or to restore generation operating reserves under the new Energy Emergency Alert Level 4 unless to not do so creates a risk to the Interconnection.
SERC OC Review Group	No	The SERC OC Review Group recommends two changes to R8. The first is to add the term "appropriate" to the requirement and the second recommendation is to move R8 to R2 as a new Part 2.4 and eliminate R8.Current R8 language: The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert after the Balancing Authority has performed the steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. Proposed R8 language: The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert after the Balancing Authority has performed the appropriate steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. Proposed R8 language moved to a new R2, new Part 2.4: The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert after the Balancing Authority has performed the appropriate steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. This move to R2, new Part 2.4 will permit deleting R8. If the SDT accepts the R8 change then M8 will also require

Organization	Yes or No	Question 13 Comment
		inserting the term "appropriate" into the measure to be consistent with R8. Current R8 language: Each Balancing Authority who, after performing the steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition, will have and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that it requested its Reliability Coordinator to declare a NERC Energy Emergency Alert in accordance with Requirement R8.Propose M8 language: Each Balancing Authority who, after performing the appropriate steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition, will have and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that it requested its Reliability Coordinator to declare a NERC Energy Emergency Alert in accordance with Requirement R8.If the EOP SDT accepts moving R8 to a new R2, Part 2.4 then the team recommends the following to the M2:Current M2 language: Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R2.Proposed M2 language: Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2. In the case where each Balancing Authority who, after performing the appropriate steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition, will have and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that it requested its Reliability

Organization	Yes or No	Question 13 Comment
		Coordinator to declare a NERC Energy Emergency Alert in accordance with Requirement R8.
ACES Standards Collaborators	No	The Emergency Operating Plan should not have to be exhausted to notify the RC of an EEA. Part of the Emergency Operating Plan should be when to notify other entities that will be impacted, including when to request an EEA from the RC. It is better for reliability to have the BA communicating with the RC if the BA anticipates a deficiency, rather than requiring the BA to exhaust all steps first. Furthermore, this requirement actually conflicts with the requirements to have Emergency Operating Plans in R1 and R2 because it requires these Emergency Operating Plans to be fully implemented. This would include manual load shedding in Part 2.2.8. Per the requirements in Attachment 1, an EEA3 should be issued when load management has been issued but it can't without violating R8 because the Emergency Operating Plan steps have not been fully exhausted. We recommend removing R8 from the standard and incorporating the notification into R1 and R2.
DTE Electric	No	Requesting the RC to declare a NERC EEA should be an integral part of a BA's plan. As written, "..after the Balancing Authority has performed the steps in its Emergency Operating Plan..." implies the entire BA plan has to be executed prior to requesting an EEA level. This can be interpreted as the BA must get all the way to manual load shed before requesting "Alert 1 - Forecast the need for an Energy Emergency". This comment is complementary to the suggestion in comment 5 regarding inclusion of EEA levels in the Emergency Operating Plan. Suggest rewriting R8 as follows: "The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert when conditions warrant in accordance with the Balancing Authority's Emergency Operating Plan."

Organization	Yes or No	Question 13 Comment
Xcel Energy	No	No, as proposed, the emergency plan will include a process to include manual load shedding. As written, R8 says that the BA can only ask for the RC to declare an EEA after it has completed the steps in the plan. So the BA must cut interrupt loads before the RC can declare an emergency. That should not be the intent of the standard. Additionally, R8 appears to conflict with R9. R8 tells the BA to request that the RC declare an emergency only after it has completed the steps in its plan. R9 tells the RC to declare an emergency if the BA or LSE is either experiencing an emergency or a potential emergency. So the RC must declare an emergency when the BA is potentially experiencing the emergency, but the BA can only request the RC declare after all steps of the plan have been completed. By the time the BA has completed the steps in its plan, the RC must have acted under R9. Requirment R8 should be removed from the proposed standard. The BA already has an obligation to notify the RC under R7 that it is experiencing trouble. There is no need to have the BA call back to request that the RC do something that the RC can do on its own and is required to do under the proposed R9.
Electric Reliability Council of Texas, Inc.	No	The inclusion of “NERC” before Energy Emergency Alert is unnecessary and could be problematic potentially from a compliance point of view. EEA is a qualitative term under the NERC standards. The specific system conditions that define EEAs are determined by the relevant regional operational rules. Referring to an EEA as a NERC EEA could be interpreted as implying there is a NERC standard for triggering EEA conditions, which is not true. To mitigate the potential for introducing this ambiguity, the word “NERC” should not be used in conjunction with EEA. Although ERCOT appreciates the intent of R8, the practical implications of the sequence of actions reflected in the standard could be problematic in practice. For example, in ERCOT, where ERCOT is the sole BA and RC, emergency operating plans are used to address EEA events. Yet, under R8 it is contemplated that the BA

Organization	Yes or No	Question 13 Comment
		would exhaust its emergency operating options prior to the declaration of an EEA. This creates a practical disconnect in ERCOT because at that point ERCOT would have been in an EEA situation and executed its relevant emergency procedures. In addition, R8 is problematic due to the removal of the CPS and DCS criteria as part of the original requirement, which were included to highlight the area imbalance and the circumstances where an LSE or BA was imbalanced and leaning on its neighbors to an unacceptable degree. In those circumstances the BA/LSE was required to exercise all available options, , up to and including firm load shed to help protect the interconnection. While the requirements are still similar in nature, some of the sub-requirements are not captured in R2, such as deploying all available operating reserve or requesting emergency assistance.
Public Service Enterprise Group	Yes	R8 should reference Attachment 1 - EOP-011. It should be modified to say The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert [ADD: per Attachment 1-EOP-011-1]....
City of Tallahassee	Yes	While TAL supports the proposed requirement, we maintain that more clarity is needed regarding “the steps in its Emergency Operating Plan”. TAL recommends changing the language to include “appropriate steps” or “necessary steps”. It is not necessary for all steps in the plan be completed prior to requesting an EEA. This should be allowed.
Arizona Public Service Company	Yes	
Florida Municipal Power Agency	Yes	
Northeast Power Coordinating Council	Yes	
ISO/RTO Standards Review Committee	Yes	

Organization	Yes or No	Question 13 Comment
Florida Power & Light	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
Hydro One	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Consumers Energy Company	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
Lincoln Electric System	Yes	
City of Austin dba Austin Energy	Yes	

14. The EOP SDT has revised EOP-002-3.1, Requirement R8 and included it in EOP-011-1 as Requirement R9. Do you support the proposed requirement? If not, please provide specific suggestions for improvement, including alternate language

Summary Consideration: After consideration of comments received, the EOP SDT has removed the Load-Serving Entity. Also in response to comments, the EOP SDT has removed "NERC" from in front of "Energy Emergency alert."

Organization	Yes or No	Question 14 Comment
MRO NERC Standards Review Forum	No	Since LSE is included in R9, it will need to be added throughout the Standard, where applicable.
Dominion	No	Dominion suggests that Load-Serving Entity be removed from this requirement. If the SDT wants to require that a LSE experiencing a potential or actual Energy Emergency notify an entity, that entity should be its BA (therefore suggest this be included as a sub-requirement to R2). Dominion does not believe that such a requirement or sub-requirement is necessary and would suggest that this decision be left to each BA.
SPP Standards Review Group	No	Delete 'NERC' in the last line of the Requirement. Change 'experiencing' to 'experience' in the 2nd line of M9. Also delete 'NERC' in the next to last line of M9.
Xcel Energy	No	The answer to this question is dependent upon how the drafting team addresses the conflict between R8 and R9 identified in question 13 above.
Public Service Enterprise Group	No	LSEs should not be subject to the standard since their BAs are subject to it. R9 should be modified to eliminate phrase "a Load Serving Entity." See our response in question 17, paragraph 2, which provides additional justification for this deletion.
ReliabilityFirst	No	ReliabilityFirst offers the following comments for consideration:1. Requirement R9 - ReliabilityFirst believes there should a timeframe associated with how long a

Organization	Yes or No	Question 14 Comment
		Reliability Coordinator has to initiate a NERC Energy Emergency Alert following a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency. ReliabilityFirst recommends the following for consideration: "Each Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate a NERC Energy Emergency Alert, as detailed in Attachment 1[, within 30 minutes of request.]"
ACES Standards Collaborators	Yes	We thank the drafting team for clarifying that the Load Serving Entity is not applicable. We would like to see this language in an RSAW.
Arizona Public Service Company	Yes	
Florida Municipal Power Agency	Yes	
Northeast Power Coordinating Council	Yes	
Duke Energy	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company	Yes	

Organization	Yes or No	Question 14 Comment
Generation and Energy Marketing		
SERC OC Review Group	Yes	
DTE Electric	Yes	
ISO/RTO Standards Review Committee	Yes	
Florida Power & Light	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
American Electric Power	Yes	
Hydro One	Yes	
Idaho Power Company	Yes	
Independent Electricity System Operator	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Consumers Energy Company	Yes	

Organization	Yes or No	Question 14 Comment
CenterPoint Energy	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	
Lincoln Electric System	Yes	
City of Austin dba Austin Energy	Yes	

15. The EOP SDT has revised Attachment 1 of EOP-002-3.1. Do you support the proposed revisions to Attachment 1? If not, please provide specific suggestions for improvement

Summary Consideration: The EOP SDT has restored the previous three alert levels of Attachment 1 in response to industry comments received. Attachment 1 has been through an additional revision subsequent to the informal comment period due to (1) industry comments received and (2) in a collaborative effort with the standard drafting team for BAL-002. The revisions are mapped within the Project 2009-03 Emergency Operations EOP-011-1 Mapping Document, as well.

Organization	Yes or No	Question 15 Comment
Dominion	No	Dominion believes the reporting hierarchy should be preserved so that only BA and TOP communicate with the RC. Entities that may be, or are, energy deficient (LSE) should have to communicate that information to their BA. The BA's Emergency Operating Plan (R2) should include one or more steps to request its Reliability Coordinator to declare a NERC Energy Emergency Alert as necessary (there are 3 levels, we think there probably needs to be multiple steps and a request at each level).
SPP Standards Review Group	No	We suggest the last line of the 1st paragraph of the Introduction be modified to read 'Entity within its Reliability Coordinator Area which is experiencing an Energy Emergency.' Change three levels to four levels in the Introduction under Section B. Energy Emergency Alert Levels. In the 2nd bullet under Circumstances in Section 3. Alert 3 - ..., change 'implemented' to 'activated.' Modify Section 3.4 to read 'If Transmission limitations are contributing to the Energy Emergency, the Reliability Coordinator should review Transmission outages and work with the applicable Transmission Operator to see if it's possible to return to service the Transmission element(s) that could relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).'Modify Section 3.5.2 to read 'Initiate curtailment of contractually interruptible Loads and activate demand-side management. Initiate curtailment of contractually interruptible retail Loads and activate demand-side management within provisions of the agreements.' Modify the

Organization	Yes or No	Question 15 Comment
		2nd and 3rd sentences in Section 4.3 to read 'Reevaluation of SOLs and IROLs should be coordinated with other impacted Reliability Coordinators and only after agreement has been reached with the Balancing Authority(ies) or Transmission Operator(s) whose equipment would be affected. SOLs and IROLs should only be revised as long as an Alert 4 condition exists, or as allowed by the Balancing Authority(ies) or Transmission Operator(s) whose equipment is at risk. Modify Alert 0 - Termination. to read 'When the Energy Deficient Entity believes it will be able to supply its customers' energy requirements, it should request its Reliability Coordinator to terminate the EEA.
Northeast Power Coordinating Council	No	While the initial Attachment 1 is largely intact, we notice that the notification details under an Alert 2 have been removed. The mapping document does not provide the rationale for the removal, nor is it presented in any of the technical justification document. We see the need for having such details in the revised Attachment 1, but are not provided the basis of the removal to aid an assessment. Please provide the rationale.
Duke Energy	No	See comments on 16. If the decision is made to move this to the NERC Glossary of Terms and a Guidance Document, Duke Energy will do a thorough review of Attachment 1 and provide necessary comments.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Power Company; Southern Company Generation; Southern Company	No	Southern prefers the previous three levels in the current Attachment 1 and sees only minimum advantages to the addition of the fourth level. Southern does believe that some of the clarifications in the new Attachment of the existing wording is an improvement. If the SDT chooses to keep the 4 levels then we have the following comments: Alert Level 2 refers to "available resources" - Does that include demand side resources or just generation? Does the SDT believe that demand side options are prohibited from being used unless an Alert Level 3 is declared? This needs to be clarified based on the heading of Alert Level 3. Item 3.5.3 refers to Emergency Assistance through an operating reserve sharing program. Not all BAs have Operating Reserve Sharing programs and not all emergency assistance is obtained

Organization	Yes or No	Question 15 Comment
Generation and Energy Marketing		through operating reserve sharing programs. The new EOP-011 has lost the concept of BAs requesting emergency assistance directly from other Bas without the use of a reserve Sharing Agreement. Seeking emergency assistance through RC coordination efforts needs to be emphasized since it often may be the primary mechanism for restoring reserves and avoiding manual load shed.
SERC OC Review Group	No	The SERC OC Review Team requests clarification on 1. Alert 1 - Forecast the need for an Energy Emergency. Circumstances: o Energy Deficient Entity foresees the need to issue alerts in the upcoming operating window and is concerned about Operating Reserves.The specific concern centers on what is meant by the phrase “upcoming operating window”. As written each entity could select a different “upcoming operating window”.
DTE Electric	No	In the second line of the Introduction of section B, change “NERC has established three levels...” to “NERC has established four levels...” Alert 1: The purpose of Alert 1 is an Energy Deficient Entity is projecting to move into Alert 2, 3, or 4. Operating Reserves are addressed in Alert 2 and 3 so do not need to be mentioned in Alert 1. Consider changing Alert 1 Circumstances to the following: “Energy Deficient Entity foresees the need to request the Reliability Coordinator issue Alerts 2, 3, or 4 in the upcoming operating window.” Alert 3 Circumstances: The second bullet has vague language “...implemented its approved Emergency Operations Plan”, it does not specify what steps have been implemented. Since alert 3 is supposed to address “Load management procedures in effect”, consider adding examples of Load management to this bullet. NERC EOP-002-3.1 alert 2 bulleted list adequately describes Load management: Public appeals to reduce demand. Voltage reduction. Interruption of non-firm end use loads in accordance with applicable contracts Demand-side management. Utility load conservation measures.
ISO/RTO Standards Review Committee	No	While the initial Attachment 1 is largely intact, we notice that the notification details under an Alert 2 have been removed. The mapping document does not provide the rationale for the removal, nor is it presented in any of the technical justification

Organization	Yes or No	Question 15 Comment
		documents. While we believe that there is a need to keep such details in the revised Attachment 1, we have not been provided the basis of the removal to aid an assessment. Please provide the rationale.
Florida Power & Light	No	Current attachment 1 is adequate and adding an additional alert does not add value as forecasted conditions are covered under the existing attachment.
City of Garland	No	Concern - Do not see a benefit to BES reliability or security from revising the Alert levels that would justify the large amount of administrative man-hours that would have to be expended at both the ISO level and at the Registered Entity level. In ERCOT and probably other ISOs, the ISO utilizes Protocols and Operating Guides to operate the various functions of the electric system. Both of these will have to be revised as they both currently reflect the current Alert levels in EOP-002 Attachment 1. Registered Entities also have procedures detailing that Entity's course of action when a RC issues a certain Alert level which would have to be rewritten. Additionally, anyone who has anything to do with electric system operations knows what the current Alert levels are, what they mean, and what actions are to be taken. If the Alert levels are changed, then everyone has to be retrained. Recommendation: Leave the current Alert levels the same. ERCOT has 3 pre-alert notifications based on actual or projected system conditions (Operating Condition Notices, Emergency Advisories, and Emergency Watches) - all designed to communicate prior to reaching the first Alert level that there are concerns about a potential energy deficiency. I have to believe that other ISOs have similar pre-alert notifications though the naming conventions probably vary.
Idaho Power Company	No	No need to create an Alert 4 category. The existing alerts 0-3 seem to be adequate.
Xcel Energy	No	The drafting team needs to modify the attachment further. The attachment should use defined terms or periods in order to ensure clarity. As an example, what is the "operating window" used under the Alert 1 section? Is it the next hour, next day, or

Organization	Yes or No	Question 15 Comment
		next week? The attachment must provide clarity if it is to be included with the standard.
Independent Electricity System Operator	No	While the initial Attachment 1 is largely intact, we notice that the notification details under an Alert 2 have been removed. The mapping document does not provide the rationale for the removal, nor is it presented in any of the technical justification document. We see the need for having such details in the revised Attachment 1, but are not provided the basis of the removal to aid an assessment. Please provide the rationale.
Public Service Enterprise Group	No	We recommend the following changes to Attachment 1-EOP-011-1:1. Consistent with our request in paragraph 2.a. in question 17 below to remove LSE from the definition of Energy Alert, please delete “Load-Serving Entity” from first paragraph and also the second paragraph that defines an “Energy Deficient Entity.”2. Combine Alert 2 and Alert 3 into one single Alert 2. Demand response resources are a part of a BA’s total resources that includes generation resources. Alert 2 now says “All available resources in use” which is not factually correct unless demand response resources are included. Alert 2 is proposed to be changed as shown below. (For the SDT’s information, the phrase “controllable and dispatchable Demand Side Management Load” used below is taken from the definitions of “Demand Side Management” and “Total Internal Demand” in MOD-031-1 that is under development in Project 2010-04 Demand Data (MOD C).) SUMMARY OF PROPOSED CHANGES TO ALERT 22. Alert 2 - All [ADD:forecasted] available resources (generation and controllable and dispatchable Demand Side Management Load) are committed [ADD: and interruption of Firm Demand is imminent].Circumstances: o Energy Deficient Entity is experiencing conditions where all available resources (generation and controllable and dispatchable Demand Side Management Load) are committed to meet [STRIKE:firm Load][ADD: Firm Demand], firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves. o (Deleted the first bullet under Alert 3.) o Energy Deficient Entity has implemented its approved Emergency Operations Plan. During Alert 32, Reliability Coordinators, Balancing

Organization	Yes or No	Question 15 Comment
		Authorities and Energy Deficient Entities have the following responsibilities: OTHER CHANGES: Change the “3” in 3.1 through 3.5 to “2” so that “3.1” becomes “2.1, etc.” Make similar changes to 3.5.1 through 3.5.3. In addition, change the language in existing 3.5.2 as follows[STRIKE:3][ADD:2].5.2 Initiate [STRIKE: contractually interruptible Loads and demand-side management curtailed][ADD:interruption of controllable and dispatchable Demand Side Management Load.] Initiate [STRIKE: contractually interruptible retail Loads curtailed, and demand-side management activated][ADD:interruption of non-Firm Demand] within provisions of their agreements.3. Make these changes to Alert 4 follows: SUMMARY OF PROPOSED CHANGES TO ALERT 4[ADD:3.] Alert [STRIKE:4][ADD:3] - [ADD:Firm Demand][STRIKE:Load] interruption [STRIKE: imminent or] in progress.OTHER CHANGES: Change the first bullet to “Energy Deficient Entity” [STRIKE: foresees or] has implemented interruption of [ADD:Firm Demand][STRIKE:firm Load obligation interruption]. Change the “4” in 4.1 through 4.4 to “3” so that “4.1” becomes “3.1,” etc.” Also change “4.4.1” to “3.4.1.” In existing 4.1, change “Alert 4” to “Alert 3” in two places.
Manitoba Hydro	No	(1) Attachment 1: This Attachment states that “NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements and nothing in these procedures should be interpreted as changing those obligations.” This provision is both unclear and problematic for Canadian registered entities. First, the reference to “FERC-approved tariffs and other agreements” is inappropriate. Canadian tariffs are not regulated or approved by FERC, unless the Canadian entity has market-based rate authorization from FERC. In some cases tariffs are approved by Canadian regulators and in other jurisdictions they are authorized under provincial law. Furthermore, most Canadian energy sale agreements are either not approved by a regulator or only approved to the extent that they involve an international export. More importantly, if this clause in the attachment was intended to state that the standard does not override tariffs and agreements in the event of a conflict, then such wording would not be legally effective in Canada where a single regulator does not perform the function of approving Canadian tariffs, energy sale

Organization	Yes or No	Question 15 Comment
		agreements and NERC standards, thereby having the power to reconcile conflicts. In Canada this would be a matter of statutory provisions on point and may vary from province to province. Legislation governing NERC standards may take precedence over contracts and tariffs. Therefore, this provision should be deleted
Tacoma Power	No	Stating there are “three” levels of Energy Emergency Alerts, when there are actually “five” (including Level 0) is a constant source of confusion amongst trainees and junior Operators. In many regions, these standards are something that the Operator only works with during training classes, so we need to remove any confusion where possible. Please fix this.
City of Austin dba Austin Energy	No	City of Austin dba Austin Energy (AE) requests clarification on the changes to Attachment 1 and the justification for those changes. Renumbering the EEA levels (and adding an additional level) could potentially create confusion; the benefit of any changes would need to offset their cost.
ACES Standards Collaborators	Yes	Adding an additional alert level to the attachment is confusing, especially when Alert 4 requires the entity to continue actions it was doing in Alert 3. We strongly suggest revising this document to have bright line differences between each alert level. Was there a reliability need to modify the prior attachment? Were a majority of registered entities having issues with the concepts of the EEA process?
Oncor Electric Delivery Company LLC	Yes	Oncor Electric Delivery (Oncor) supports the revisions to Attachment 1 in the proposed EOP-011-1; however, Oncor cautions the separation of Energy Emergency Alert (EEA) 2 into two separate EEAs (2 and 3) since it would require a great deal of administrative revision and could limit flexibility to existing Procedures for all entities involved, with no reliability benefit from the separation. Oncor appreciates another look at this revision by the SDT. Additionally, for clarifying purposes, Oncor recommends that Responsibility 3.4 under Alert 3 in Attachment 1 should include the following changes:3.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator should review Transmission outages and work with the

Organization	Yes or No	Question 15 Comment
		Transmission Operator to see if it’s possible to return the Transmission element <back to service> that may <return the system to pre-emergency conditions or> relieve the Loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Florida Municipal Power Agency	Yes	
Hydro One	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	
Northeast Utilities	Yes	
Lincoln Electric System	Yes	
Bonneville Power Administration		In the section on Alert 3 under Circumstances, BPA believes that the second bullet “Energy Deficient Entity has implemented its approved Emergency Operations Plan” should be removed because Load Serving Entities are included in the definition of Energy Deficient Entities but they do not have “approved Emergency Operations Plans” so this cannot happen when the EDE is an LSE. Also, looking at R2, a BA would be exercising their Plan at least by Alert level 1 so of course they would have

Organization	Yes or No	Question 15 Comment
		implemented it by EEA 3. That bullet is not necessary and is in direct conflict with the fact that LSE's aren't required to have plans under this standard.
Consumers Energy Company		N/A to SC&M Department

16. **The EOP SDT has considered technical justification to remove Attachment 1 from the proposed EOP-011-1. If Attachment 1 were to be removed, the SDT proposes that NERC's Energy Emergency Alert levels be incorporated into the NERC Glossary as defined terms, with some of the additional information in Attachment 1 incorporated as a guidance document. Would you support this approach? If not, please provide specific suggestions for an alternate approach that you would support.**

Summary Consideration: The EOP SDT appreciates your comments. Being this was closely a split issue, the EOP SDT has made the decision to retain Attachment 1 with EOP-011-1. The EOP SDT has restored the previous alert levels of Attachment 1 in response to industry comments received. Attachment 1 has been through an additional revision subsequent to the informal comment period due to (1) industry comments received and (2) in a collaborative effort with the standard drafting team for BAL-002.

Please note that there are several references in the documents to (3) three Energy Emergency alert levels (currently-enforce Attachment 1 from EOP-002.3.1). Through comments, it has been pointed out to the EOP SDT that there are, in fact, (4) four Energy Emergency alert levels: 0 – 3; that Alert 0 – Termination is one of (4) four alert levels. The EOP SDT, when making future reference within documents, will reference (4) four alert levels.

Organization	Yes or No	Question 16 Comment
SPP Standards Review Group	No	Unless there is a pressing need to remove the Attachment, we recommend leaving it where it is. This is a known document with many years of use in the industry. We're familiar with it and know how to use it. The SDT hasn't really provided any justification for moving it to the Glossary and unless the SDT can help us understand why we need to make the change, we can't support it. We also have concerns with how the Attachment would be logistically moved into the Glossary. It appears that only part of the document would go into the Glossary and the remaining material would be retained in a guidance document. Splitting the material would degrade the value of the document as it currently exists.
Florida Municipal Power Agency	No	FMPA would prefer to retain it as an attachment to the standard.

Organization	Yes or No	Question 16 Comment
Northeast Power Coordinating Council	No	Both the proposed and current approaches are acceptable. We can support defining the EEA levels through a definition, and incorporate them into the NERC Glossary. However, Attachment 1 also serves the purpose of providing necessary information associated with and required for issuing EEAs. To put some of that into the Glossary of Terms, will make the defined term very lengthy. Putting other information into a guideline document is only possible if none of the required information depicted in Attachment 1 is mandatory. Unfortunately, we are unable to locate the detailed technical justification the EOP SDT used to support the proposed removal of all information in Attachment 1 that are "requirements". Please provide them at the next posting so that we can assess the merit of this proposal. A mapping of the detailed information in Attachment 1 after the proposed removal will be very helpful. The following should be added to the Glossary of Terms as defined terms:" Energy Emergency Alert" "Energy Deficient Entity" Additional comment on Attachment 1, Alert 3 and Alert 0: Shouldn't the words here match the words used in the revised definition of "Energy Emergency" so as to say "is no longer able to meet Load?" (same as under "Alert 0")?
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	The SDT needs to provide additional guidance on the compliance implications of leaving it as an Attachment or implementing the proposal of the Attachment being incorporated into the NERC Glossary of defined terms. For example, does an Attachment to a standard imply any more compliance obligation than the same words in a guidance document?

Organization	Yes or No	Question 16 Comment
DTE Electric	No	Suggest leaving the content in Attachment 1. Moving EEA levels to the glossary and a separate guidance document will unnecessarily complicate the language of R9. As written, R9 is clear and concise.
ISO/RTO Standards Review Committee	No	While we could support defining the EEA levels through a definition, and incorporating them into the NERC Glossary, Attachment 1 also serves the purpose of providing necessary information associated with and required for issuing EEAs. Including part of that information into the Glossary of Terms will make the defined term very lengthy. In addition, moving other information to a guideline document is only possible if the information currently included in Attachment 1 is not mandatory. Unfortunately, we cannot locate the detailed technical justification the EOP SDT used to support the proposed removal of all information in Attachment 1 that are “requirements.” Please provide it with the next posting so that we can assess the merit of this proposal. A mapping of the detailed information in Attachment 1 after the proposed removal will be very helpful. While we do not support defining EEA levels as proposed, we do have the following comments regarding the proposed definition for Energy Emergency and suggestion for defining the three terms and adding them to the NERC Glossary as appropriate: In the revised definition of Energy Emergency the word “energy" has been replaced with "Load". The revised definition now seems to imply that reserves have been exhausted and a BA simply can't serve load. On the other hand, the word “energy” implies that planned dispatch has been used up and a BA must now begin to utilize reserves, which we believe is more aligned with the EEA steps. We suggest restoring the word “energy”. Further, we suggest replacing “provide” with “meet”. The revised definition will thus read: Energy Emergency - A condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer meet its customers’ expected energy requirements. We propose to define the following three terms: “Energy Emergency Alert” “Energy Deficient Entity” Emergency Operating Plans” The term Energy Emergency Alert is referenced in the standard and in Attachment 1, and is capitalized. But this term is not defined in the NERC Glossary. Similarly, the term Energy Deficient

Organization	Yes or No	Question 16 Comment
		Entity is referenced in Attachment 1 and is capitalized, but it is not defined in the NERC Glossary. Likewise, the term Emergency Operating Plan is referenced in the standard and is capitalized, but it is not defined in the NERC Glossary. These terms need to be put in lower case, or defined for use in this standard only, or defined and included in the Glossary. Additional comment on Attachment 1, Alert 3 and Alert 0: the language here should match the language used in the revised definition of "Energy Emergency" (including our proposed edits) so as to say "can no longer meet its expected energy Load." (Same comment under "Alert 0").
Florida Power & Light	No	Current Attachment 1 provides the details needed to meet the requirements.
Independent Electricity System Operator	No	We can support defining the EEA levels through a definition, and incorporate them into the NERC Glossary. However, Attachment 1 also serves the purpose of providing necessary information associated with and required for issuing EEAs. To put some of that into the glossary of term, it will make the defined term very lengthy. And putting other information into a guideline document is only possible if none of the required information depicted in Attachment 1 is mandatory. Unfortunately, we are unable to locate the detailed technical justification the EOP SDT used to support the proposed removal of all information in Attachment 1 that are "requirements". Please provide them at the next posting so that we can assess the merit of this proposal. A mapping of the detailed information in Attachment 1 after the proposed removal will be very helpful.
Public Service Enterprise Group	No	It is unclear how a new Glossary term for Energy Emergency Alert would be defined by the SDT and what would remain in Attachment 1 as guidance. We would need to see the proposed EEA definition and a revised Attachment 1.
CenterPoint Energy	No	CenterPoint Energy does not believe that Energy Emergency Alert levels should be codified in the NERC Glossary and does not support such an approach. The Company believes the NERC Glossary should be reserved for definitions of terms used throughout the Reliability Standards. Terms used in one or two Standards should be

Organization	Yes or No	Question 16 Comment
		defined in the Standard where the term is utilized. CenterPoint Energy recommends keeping Attachment 1 in the proposed EOP-011-1.
Lincoln Electric System	No	Recommend the Energy Emergency Alert levels remain within the document where they are used.
Oncor Electric Delivery Company LLC	No	Oncor prefers and supports the use of the revised Attachment 1 in proposed EOP-011-1, with the changes suggested in Question 15.
City of Austin dba Austin Energy	Yes	City of Austin dba Austin Energy (AE) could work with either format as long as any changes are identified and justified.
Duke Energy	Yes	Duke Energy agrees with this approach for the following reason. By moving Attachment 1 to the NERC Glossary of Terms and adding a Guidance Document, it provides subsequent SDTs the flexibility to amend the EEA levels as necessary within one Standards Development project without having to initiate multiple Standards Development projects simultaneously. This prevents the posting of projects for the sole purpose of modifying an Attachment to a Standard.
ACES Standards Collaborators	Yes	We could support the removal of attachment one, as long as the alert levels remain the same (zero through 3). If the drafting team is going to revise the alert levels as proposed in the current draft by including alert level 4, then it would be better to keep the attachment with the standard.
City of Garland	Yes	Agree with this but do not agree with revising Alert levels - see comments on question 15
Idaho Power Company	Yes	No need to create an Alert 4 category. The existing alerts 0-3 seem to be adequate.

Organization	Yes or No	Question 16 Comment
Xcel Energy	Yes	This could be preferential to the current attachment. Since the current attachment needs significant work, this process might address our concerns in a better way than the current proposal.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
Bonneville Power Administration	Yes	
Hydro One	Yes	
Manitoba Hydro	Yes	
Tacoma Power	Yes	
Consumers Energy Company	Yes	
Wisconsin Electric	Yes	
Pepco Holding Inc.	Yes	
City of Tallahassee	Yes	

17. **Do you have any other comments regarding proposed EOP-011-1, not included above, that you would like to provide to the EOP SDT? If so, please provide specific comments for improvement**

Summary Consideration: The EOP SDT appreciates the many comments received. The EOP SDT has made several of the clarification edits suggested. With the proposal of a revision to a definition, the EOP SDT is obligated to list standards the term is used in. As stated in the standard, the EOP SDT does not believe the proposed revision changes the intent of the requirements or definitions. The EOP SDT is not suggesting any changes to the intent of the requirements in BAL-002-WECC-2, this standard was listed because the EOP SDT was obligated to do so, as the term is used in this standard. There were comments made regarding "Emergency Operating Plan," noting that together this is not a defined term. The intent of the EOP SDT is the defined term "Emergency" and the defined term "Operating Plan." The EOP SDT appreciates the time that is involved in reviewing the standard and the documents during the informal comment period. The comments received has provided the EOP SDT an opportunity to incorporate many of suggestions made in an effort to improve upon EOP-011-1 prior to posting for initial comment period and ballot.

Organization	Yes or No	Question 17 Comment
Arizona Public Service Company	No	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern	No	

Organization	Yes or No	Question 17 Comment
Company Generation; Southern Company Generation and Energy Marketing		
SERC OC Review Group	No	The OC Review Group request further clarification on R1 and R2 minimum set of elements. There are cases where specific elements may be utilized for non-emergency reasons. For example, voltage reduction, load curtailable load and interruptible load can be utilized for non-emergency purposes. Would these activities constitute plan implementation? C. 1.1.2 Evidence Retention: If the EOP SDT accepts deleting R8 and creating a new R2, Part 2.4 then the evidence retention section would require modification. Current language: The Balancing Authority shall maintain evidence of compliance since the last audit for Requirements R6 and R8 and Measures M6 and M8.Proposed language: The Balancing Authority shall maintain evidence of compliance since the last audit for Requirements R2 and R6 and Measures M2 and M6.The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
DTE Electric	No	
Florida Power & Light	No	
PacifiCorp	No	
Bonneville Power Administration	No	
Consumers Energy Company	No	

Organization	Yes or No	Question 17 Comment
American Transmission Company, LLC	No	
Wisconsin Electric	No	
City of Tallahassee	No	
MRO NERC Standards Review Forum	Yes	We appreciate the efforts of the SDT and the FYRT to consiladiate the 3 existing standards from the EOP group into a single standard that is clearer and the requirements are organized by Functional Entity.
Dominion	Yes	M1 contains “that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability Coordinator,” this also needs to be included in M2.
SPP Standards Review Group	Yes	Background Section: In the 3rd line of the paragraph below the bullet points, spell out Bulk Electric System and then follow it with the BES in parentheses.
Florida Municipal Power Agency	Yes	FMPA appreciates the work of the SDT to vastly improve the standards.
Northeast Power Coordinating Council	Yes	In the section of the standard entitled “Definitions of Terms Used in Standard”, the SDT has defined Energy Emergency as: “Energy Emergency - a Condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide expected Load requirements”. This is a revision of the definition in the NERC Glossary is unclear because it does not define the point at which the Load-Serving Entity or Balancing Authority should decide that they can no longer provide expected Load requirements. Is that when it can no longer provide all necessary Load requirements? Or is it intended to mean that a significant portion of the Load requirements can no longer be provided - and if so, what constitutes a significant portion? More clarity is needed in the standard. Suggest revising the definition by

Organization	Yes or No	Question 17 Comment
		changing “provide” to “meet” and delete “requirements”. The proposed definition would then read “...can no longer meet its expected Load.” Even if it is preferable to not define the specific point in the standard, the standard should state that the Energy Emergency condition will be defined and documented by the Balancing Authority or the Load Serving Entity. Comments on BAL-002-WECC-2 - Contingency Reserve: We are unclear on the inclusion of “BAL-002-WECC-2 - Contingency Reserve” and Requirement R1 on P. 3, Definitions of Terms Used in Standard. Please clarify. Also, “energy emergency” is not capitalized in one of the R1.1 bullets here - it should be because it is a defined term.” Emergency Operating Plan” is capitalized but it is not a defined term in the Glossary of Terms and there is no definition included in this draft of the standard. A definition should be added or it should not be capitalized. Comment on R1 and R5: the standards talk about “operating Emergencies.” There are definitions for “Energy Emergency,” “Capacity Emergency,” and “Emergency” (or “BES Emergency”). If the definition of “Emergency” captures what is needed, then the word “operating” isn’t needed and should be deleted. The phrase “operating Emergency” also appears in R5.Comment on R2, R6, and R8: Energy Emergency has a definition in the draft - but what constitutes a “capacity” is not capitalized in “capacity Emergency.” The definition of “Capacity Emergency” in the Glossary is “[a] capacity emergency exists when a Balancing Authority Area’s operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.” So, if this is what the standard means by “capacity Emergency,” then it should be capitalized. R2 should read: “to mitigate Capacity Emergencies and Energy Emergencies.” Same comment applies to R6 and R8.
Duke Energy	Yes	Duke Energy suggests replacing “requirements” with “obligations” in the definition of Energy Emergency. Our proposed definition is as follows: “Energy Emergency - A condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide its expected Load obligations.” We believe

Organization	Yes or No	Question 17 Comment
		obligated is a more appropriate term because LSEs or BAs are not required to serve load, rather they are obligated to do so.
ACES Standards Collaborators	Yes	(1) The VSL table is blank. We cannot support a standard that is incomplete and does not provide guidance on how enforcement will be interpreting this standard and translating violations into monetary penalties.(2) The guidelines and technical basis section is blank. We suggest waiting to post draft standards until they are complete.(3) Thank you for the opportunity to comment.
ISO/RTO Standards Review Committee	Yes	Requirement R8 requires a BA to request its RC to declare EEA when necessary. R9 requires the RC to initiate an EEA when its BA or LSE is experiencing a potential or actual Energy Emergency. It implies that a RC needs to be watching the conditions in its area, and initiate the EEA as needed. However, such a process could also be initiated by a BA's request under R8. If R9 is retained as written, then R8 could be removed, and a new requirement be added to require the RC to monitor the energy conditions in its area to detect potential or actual Energy Emergency of its BAs and LSEs. If R8 is retained, then we suggest that a new requirement be added to require the RC to monitor the energy situation as indicated above, plus revise R9 as follows: R9. Each Reliability Coordinator that receives notification from a Balancing Authority that is is unable to resolve a capacity or Energy Emergency condition or that assesses that a Balancing Authority or Load-Serving Entity is experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate a NERC Energy Emergency Alert, as detailed in Attachment 1. Comments on BAL-002-WECC-2 - Contingency Reserve: We are unclear on the inclusion of "BAL-002-WECC-2 - Contingency Reserve" and Requirement R1 on P. 3, Definitions of Terms Used in Standard. Please clarify. Also, "energy emergency" is not capitalized in one of the R1.1 bullets here - it should be because it is a defined term. Global Comment: "Emergency Operating Plan" is capitalized but it is not a defined term in the Glossary of Terms and there is no definition included in this draft of the standard. A definition should be added or it should not be capitalized. Comment on R1 and R5: the standards talk about "operating Emergencies." There are definitions for "Energy

Organization	Yes or No	Question 17 Comment
		Emergency," "Capacity Emergency," and "Emergency" (or "BES Emergency"). If the definition of "Emergency" captures what is needed, then the word "operating" should be deleted. The phrase "operating Emergency" also appears in R5.Comment on R2, R6, and R8: Energy Emergency has a definition in the draft - but "capacity" is not capitalized in "capacity Emergency." The definition of "Capacity Emergency" in the Glossary is "[a] capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements." So, if this is what the standard means by "capacity Emergency," then it should be capitalized. R2 should read: "to mitigate Capacity Emergencies and Energy Emergencies." Same issue in R6 and R8.
Hydro One	Yes	In the section of the standard entitled "Definitions of Terms Used in Standard", the SDT has defined Energy Emergency as: "Energy Emergency - a Condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide its customers' expected energy Load requirements". This definition is also in the NERC Glossary. This statement is unclear because it does not define the point at which the Load-Serving Entity or Balancing Authority should decide that they can no longer provide expected Load requirements. Is that when they can no longer provide all necessary Load requirements? Or is it intended to mean that a significant portion of the Load requirements can no longer be provided - and if so, what constitutes a significant portion? More clarity is needed in the standard. Even if it is preferable not to define the specific point in the standard, the standard should state that the Energy Emergency condition will be defined and documented by the Balancing Authority or the Load Serving Entity.
Idaho Power Company	Yes	When Capacity Emergencies are mentioned they are not capitalized, it is a NERC defined term. Example: R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate

Organization	Yes or No	Question 17 Comment
		capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include
Xcel Energy	Yes	Xcel Energy appreciates the efforts of the drafting team to date and believes the consolidation of standards is an improvement. The drafting team has addressed many of the issues currently identified with the existing standards. We look forward to additional improvements in the next revision of the draft standard.
Independent Electricity System Operator	Yes	We are unclear on the inclusion of “BAL-002-WECC-2 - Contingency Reserve” and Requirement R1 on P. 3, Definitions of Terms Used in Standard. Please clarify.
Public Service Enterprise Group	Yes	1. The Emergency Operating Plans developed under R1 and R2 may contain Critical Energy Infrastructure Information (CEII). There should be a requirement that if such plans contain CEEI, (a new term that would need to be defined in the NERC Glossary but which FERC has defined) such information should be redacted before making the plans available in a public domain. Furthermore, such plans should be maintained by entities in a manner consistent with the treatment of CEII.2. We recommend two changes in the definition of Energy Emergency: a. Eliminate the reference to Load-Serving Entity and just reference Balancing Authority. The LSE’s BA should, through R9, be the lowest level entity that experiences an Energy Emergency. A BA that dispatches for several LSEs may be able to resolve an LSE energy emergency issue, and if it cannot, the BA should act under R9. See our response to question 14 that also recommended deletion of Load Serving Entity from R9.b. A NERC Glossary term is already defined for “Firm Demand.” We therefore recommend that “Firm Demand” replace “Load.” There is no Energy Emergency when a BA expects to interrupt non-Firm Load. With these changes, “Energy Emergency” would be defined as “A condition when a Balancing Authority has exhausted all other options and can no longer provide its customers’ expected Firm Demand requirements.”
Ingleside Cogeneration LP	Yes	As a GO/GOP, ICLP would like to reinforce the project team’s decision to defer work on generator-related extreme weather preparedness. The issue has been fully vetted

Organization	Yes or No	Question 17 Comment
		under other project headings - and will be actively re-reviewed in the gas/electricity interdependency initiative that FERC is driving. Furthermore, the local regulatory authorities are aggressively taking the lead on winterization planning. In our specific case, the Texas PUC has already required that we submit detailed winterization plans for a quality assessment - and any addition to the EOP requirements would just increase our administrative overhead. We are aware that the priority on this topic may change as a result of the series of winter storms that North America experienced earlier this year, but it is premature to rush the process at this point. There are several high visibility standard development efforts that are competing for our resources - CIP Version 5 comes immediately to mind - and the effect of the recently approved generator validation standards has yet to be determined. As such, we believe the strategy taken in the initial draft of EOP-011-1 is sufficient as it stands; and that that the issue of generator winter preparedness is being actively and effectively pursued elsewhere.
Manitoba Hydro	Yes	(1) The term “BAL-002- WECC -2-Contingency Reserve” is included in the definition section, yet is not a defined term that is used in the standard. This should be deleted. Alternatively, if the terminology is not deleted, there is a drafting inconsistency in R1.2 and R1.3. In these sections the term “load” is not capitalized as it is elsewhere in the standard, thereby implying a different meaning than the term “Load” as defined in the NERC Glossary. If the same meaning was intended, this term should be capitalized. Also, in R1.3, the reference to the U.S. Code of Federal Regulations is inappropriate for non- FERC jurisdictional NERC registered entities. Since Canadian entities are not bound by U.S. law, the reference should be deleted or confined to U.S. registered entities. (2) The definition of “Emergency Energy “refers to a condition where “all other options” have been exhausted. However, since the definition does not refer to any options, it is not clear what the phrase “other options” refers to. This should be clarified. For instance, is the intention to refer to all options other than manual Load shedding?

Organization	Yes or No	Question 17 Comment
Tacoma Power	Yes	Tacoma Power agrees with the overall idea of combining three Energy and Capacity Emergency related plans into one standard, though we are concerned about expanding the new standard to include the Transmission System Emergencies. Our concern is that this standard might be mis-interpreted and/or mis-applied in an attempt to address any and all Transmission emergencies (emphasis on the lower case "e" in emergencies). We feel the standard development team has done a pretty good job so far in addressing this and hope they keep this concern in mind as they continue to develop this standard.
CenterPoint Energy	Yes	CenterPoint Energy appreciates the work of the SDT and the opportunity to provide comments. CenterPoint Energy cannot support the proposed Standard as it is currently drafted for the reasons stated above. The Company understands this is a first draft and provides these comments in anticipation of being able to support a future version of the Standard.
Pepco Holding Inc.	Yes	
Northeast Utilities	Yes	Global Comment: “Emergency Operating Plan” is capitalized but it is not a defined term in the glossary of terms and there is no definition included in this draft of the standard. A definition should be added or it should not be capitalized. Comment on R1 and R5: the standards talk about “operating Emergencies.” There are definitions for “Energy Emergency,” “Capacity Emergency,” and “Emergency” (or “BES Emergency”). If the definition of “Emergency” captures what is needed, then the word “operating” should be deleted. The phrase “operating Emergency” also appears in R5.Comment on R2, R6, and R8: Energy Emergency has a definition in the draft - but “capacity” is not capitalized in “capacity Emergency.” The definition of “Capacity Emergency” in the Glossary is “[a] capacity emergency exists when a Balancing Authority Area’s operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.” So, if this is what the standard

Organization	Yes or No	Question 17 Comment
		means by “capacity Emergency,” then it should be capitalized. R2 should read: “to mitigate Capacity Emergencies and Energy Emergencies.” Same issue in R6 and R8.
Lincoln Electric System	Yes	While appreciative of the drafting team’s efforts in consolidating the Emergency Operations standards, LES believes the following areas may benefit from additional clarification.R9 - Although the Load Serving Entity (LSE) is no longer referenced as an applicable entity within EOP-011-1, the references to the LSE in R9 and Attachment 1 seem to imply that there is still the expectation that the LSE retains compliance responsibilities in case of a potential or actual Energy Emergency. As an example, in Attachment 1 Section B the “Energy Deficient Entity”, which is defined as an LSE or BA in the Attachment 1 Introduction, is required to “communicate its needs to other Balancing Authorities and market participants” (Part 3.1), in addition to updating the RC of the situation “at a minimum of every hour” (Part 3.2). To ensure entities are aware of their respective obligations, recommend either including the LSE as an applicable functional entity within EOP-011-1 or else modifying R9 and Attachment 1 to remove specific references to the LSE.R1, R2 - Per R1 and R2, the Transmission Operator and Balancing Authority are required to develop, maintain and implement an Emergency Operating Plan approved by the Reliability Coordinator. Is the drafting team’s expectation that the process entities establish in R1.3 and R2.3 will take the place of a minimum review requirement? As an example, rather than require entities to review their Plan annually as part of EOP-011-1, all reviews would be accounted for as part of the entity’s revision process developed in R1.3 and R2.3.
City of Austin dba Austin Energy	Yes	City of Austin dba Austin Energy (AE) seeks clarity stating the Emergency Operating Plan required under requirement R1 can be a single document or a combination of documents. This is similar to the allowance for a plan or set of plans in currently enforceable EOP-001-2.1b.

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Standards Committee authorized moving the SAR forward to standard development 10/17/2013.
2. SAR posted for comment 11/06/13-12/05/13.
3. Informal posting for comment 03/28/14-04/28/14.

Description of Current Draft

This is the second draft of the proposed standard and is being posted for formal stakeholder comments and initial ballot. This draft includes the modifications based on the Five-Year Review Team recommendations, comments submitted by stakeholders during the SAR comment period, comments submitted by stakeholders during the informal comment period, as well as other items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
45-day Formal Comment Period with Parallel Initial Ballot	July 2014
Final ballot	October 2014
BOT adoption	November 2014
File standard with regulatory authorities	December 2014

Effective Dates

The standard shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Initial Standard	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

Definitions of Terms Used in Standard

This section includes all newly-defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The EOP SDT proposed to revise the current approved definition of **Energy Emergency** as follows:

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its ~~customers'~~ expected ~~energy~~ Load obligations.

The proposed revisions are intended to clarify that an Energy Emergency is not necessarily limited to a Load-Serving Entity. This term, or variations of it, is also used in other standards, as indicated below. The EOP SDT is obligated to review other standards in which this term is used to determine if reliability gaps or redundancies are created by the proposed revision to the defined term. The EOP SDT has made a review of other standards in which the term "energy emergency" is used and does not believe the proposed revisions change the reliability intent of requirements or definitions.

- **BAL-002-WECC – Contingency Reserve**: This standard becomes enforceable on October 1st, 2014. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **IRO-005-3.1a — Reliability Coordination — Current Day Operations** - This standard was revised under Project 2006-06 and the reference to Energy Emergency was removed from the standard. The standard was approved by the NERC BOT and filed with FERC. NERC has requested that FERC defer action on its petition and is revising this standard under project 2014-03, TOP/IRO revisions. This project is scheduled to be completed no later than January 31, 2015. The two standard drafting teams are coordinating the definition revision to ensure there are no redundancies.
- **MOD-004-1 — Capacity Benefit Margin:** This standard is being retired and replaced with MOD-001-2 — Modeling, Data, and Analysis — Available Transmission System Capability (NERC BOT approved February 6, 2014). The term "energy emergency" is not used in the new standard. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability to the existing approved standard.
- **INT-004-3 – Dynamic Transfers:** This standard was a revision to INT-004-2 under Project 2008-12. INT-004-3 was approved by the NERC BOT and filed with FERC. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **Defined term Emergency Request for Interchange:** This term is not used in any existing approved standard.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Emergency Operations**
2. **Number: EOP-011-1**
3. **Purpose:** To mitigate the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Emergency Operating Plans, and that those plans are coordinated within a Reliability Coordinator Area.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

5. **Background:**

EOP-011-1 consolidates requirements from three standards: EOP-001-2.1b, EOP-002-3.1, and EOP-003-2.

The Project 2009-03 Emergency Operations Standard Drafting Team (EOP SDT) developed EOP-011-1 by considering the following inputs:

- Applicable FERC directives;
- Five Year Review Team (FYRT) recommendations;
- Independent Expert Review Panel recommendations; and
- Paragraph 81 criteria.

The standard streamlines the requirements for Emergency operations for the Bulk Electric System (BES) into a clear and concise standard that is organized by Functional Entity. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include the following elements: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]*

1.1. Roles and responsibilities to activate the Emergency Operating Plan;

1.2. Strategies to prepare for and mitigate Emergencies including, at a minimum:

1.2.1. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an operating Emergency;

1.2.2. Voltage control;

1.2.3. Cancellation or recall of Transmission and generation outages;

1.2.4. System reconfiguration;

1.2.5. Redispatch of generation request;

1.2.6. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding;

1.2.7. Mitigation of reliability impacts of extreme weather conditions; and

1.3. Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities.

Rationale for Requirement R1: The EOP SDT examined the recommendation of the EOP FYRT and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Transmission Operator to create an Emergency Operating Plan.

Requirement R1 Part 1.2. was added to this standard for the Transmission Operator to address strategies to prepare for and mitigate Emergencies using voltage control methods, which could include switching of capacitor and reactor banks, generator reactive output, and the use of synchronous condensers.

It is the EOP SDT's intent for Requirement R1 Part 1.2.6. that what is unwanted is the use manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against cascading outages or system collapse. If an entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. The EOP SDT acknowledges that, in the formulation of manual Load shedding plans, complete exclusion of Loads armed for automatic Load shedding may not be possible. Each entity should, however, evaluate their automatic Load shedding schemes and coordinate their manual plans so that overlapping use of Loads is avoided to the extent reasonably possible.

"Emergency Operating Plan" within the requirements of EOP-011-1 is not intended as a newly-defined term. It is the intent of the EOP SDT that two defined terms are being used: the defined term "Emergency" and the defined term "Operating Plan."

M1. Each Transmission Operator will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability Coordinator; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]*

2.1. Roles and responsibilities to activate the Emergency Operating Plan;

2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency;

2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1;

2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum:

2.4.1. Generating resources in its Balancing Authority Area:

2.4.1.1. capability and availability;

2.4.1.2. fuel supply and inventory concerns;

2.4.1.3. fuel switching capabilities; and

2.4.1.4. environmental constraints.

2.4.2. Voluntary Load reductions;

2.4.3. Public appeals;

2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.4.5. Reduction of internal utility energy use;

2.4.6. Customer fuel switching;

2.4.7. Use of Interruptible Load, curtailable Load and demand response;

2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and

2.4.9. Mitigation of reliability impacts of extreme weather conditions.

2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.

Rationale for Requirement R2: To address the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1, the EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. EOP-011-1 also establishes a separate requirement for the Balancing Authority to create its Emergency Operating Plan to address Capacity and Energy Emergencies.

If any Parts of Requirement R2 are not applicable, the Balancing Authority should note "not applicable" in their plan.

The EOP SDT retained the statement "Operator-controlled manual Load shedding," as it was in the current EOP-003-2 and is consistent with the intent of the EOP SDT.

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shedding schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R2 Part 2.4.8. is to minimize as much as possible the use manual Load shedding which is already armed for automatic load shedding. The automatic Load shedding schemes are the important backstops against cascading outages or system collapse. If an entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should evaluate their automatic Load shedding schemes and coordinate their manual plans so that any overlapping use of Loads is avoided to the extent reasonably possible.

Requirement R2 Part 2.4.8 references "coordination" – the intention is that manual and automatic systems be coordinated with each other to minimize overlap of the Loads planned to be shed in each. The reference is not intended to require coordination with other entities.

The EOP SDT retained Requirement R8 from EOP-002-3.1 and added it to the Parts in Requirement R2.

M2. Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2 that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability Coordinator; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its plan was implemented in accordance with Requirement R2.

R3. Each Reliability Coordinator shall approve or disapprove, with stated reasons for disapproval, Emergency Operating Plans submitted by Transmission Operators and Balancing Authorities within 30 calendar days of submittal. *[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*

Rationale for R3: Since Requirements R1 and R2 both require a submittal for approval, Requirement R3 requires approval or disproval. This aligns with similar requirements in EOP-006-2, Requirement 5.1.

M3. The Reliability Coordinator will have documentation, such as e-mails with receipts or registered mail receipts, that it approved or disapproved, with stated reasons for disapproval, the Transmission Operator and Balancing Authority submitted and revised

Emergency Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as practical, other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R4: The EOP SDT added the words "as soon as practical" to the requirement to communicate the intent that timeliness is important, while balancing the concern that in an Emergency there may be a need to alleviate excessive notifications on Balancing Authorities and Transmission Operators. This was an existing requirement in EOP-002-3.1 for Balancing Authorities.

M4. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if it communicated the Balancing Authority's or Transmission Operator's Emergency to impacted Reliability Coordinators, Balancing Authorities, and Transmission Operators in accordance with Requirement R4.

R5. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R5: Requirement R5 was created to address the FERC directive to have the Reliability Coordinator involved to ensure that the Energy Emergency Alert gets initiated.

M5. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it initiated an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R5.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The Balancing Authority, Reliability Coordinator, and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Transmission Operator shall retain the current Emergency Operating Plan, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R1, and Measure M1.
- The Balancing Authority shall retain the current Emergency Operating Plan, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R2, and Measure M2.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R4 and R5 and Measures M3, M4, and M5.

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

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Real-time Operations, Operations Planning**	**High**	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include one of the Sub-Parts 1.2.1 - 1.2.7 as applicable.	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include two of the Sub-Parts 1.2.1 - 1.2.7 as applicable.	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include three of the Sub-Parts 1.2.1 - 1.2.7 as applicable. OR The Transmission Operator failed to have a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include four or more of the Sub-Parts 1.2.1 - 1.2.7. OR The Transmission Operator failed to have a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					include either Part 1.1 or Part 1.3. OR The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to maintain it.	Emergencies on its Transmission System. OR The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to implement it for an operating Emergency.
R2	**Real-time Operations, Operations Planning**	**High**	The Balancing Authority had a Reliability Coordinator-approved Emergency	The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate	The Balancing Authority had a Reliability Coordinator-approved Emergency	The Balancing Authority had a Reliability Coordinator-approved

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			Operating Plan to mitigate Capacity and Energy Emergencies but failed to include one of the Sub-Parts 2.4.1 – 2.4.9.	Capacity and Energy Emergencies but failed to include two of the Sub-Parts 2.4.1 – 2.4.9.	Operating Plan to mitigate Capacity and Energy Emergencies but failed to include three of the Sub-Parts 2.4.1 – 2.4.9. OR The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to include either Part 2.1 or Part 2.2 or Part 2.3 or Part 2.5. OR The Balancing Authority had a Reliability Coordinator-approved	Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to include four or more of the Sub-Parts 2.4.1 – 2.4.9. OR The Balancing Authority failed to have a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. OR The Balancing Authority had a Reliability

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to maintain it.	Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to implement it for a Capacity or Energy Emergency.
R3	**Operations Planning**	**Medium**	The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 30 days but less than or equal to 40 days.	The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 40 days but less than or equal to 50 days.	The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 50 days but less than or equal to 60 days.	The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					OR The Reliability Coordinator disapproved a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans within 30 calendar days of submittal but failed to provide the reasons for disapproval.	more than 60 days. OR The Reliability Coordinator failed to approve or disapprove, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans.
R4	**Real-time Operations**	**High**	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify other impacted Reliability Coordinators, Balancing Authorities and Transmission	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify, as soon as practical, other impacted Reliability Coordinators,

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Operators but did not do so as soon as practical.	Balancing Authorities and Transmission Operators.
R5	**Real-time Operations**	**High**	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to notify the other Reliability Coordinators, Balancing Authorities and Transmission Operators when the alert has ended.	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency Alert and hold conference calls between Reliability Coordinators as necessary to communicate System conditions.	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency Alert and notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). OR

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency Alert and notify all Balancing Authorities and Transmission Operators in its reliability area.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Attachment 1-EOP-011-1
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator (RC) in which it communicates the condition of a Balancing Authority (BA) which is experiencing an Energy Emergency.

A. General Responsibilities

1. **Initiation by RC.** An Energy Emergency Alert (EEA) may be initiated only by a RC at 1) the RC's own request, or 2) upon the request of the requesting BA.
2. **Notification**. A RC who declares an EEA shall notify all BAs and Transmission Operators (TOP) in its Reliability Coordinator Area. The RC shall also notify all other RCs of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between RCs shall be held as necessary to communicate System conditions. The RC shall also notify the other RCs, Bas, and TOPs when the EEA has ended.

B. EEA Levels

Introduction

To ensure that all RCs clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established four levels of EEAs. The RCs will use these terms when explaining Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standard. The RC may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use.**

Circumstances:

- Requesting BA is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves.
- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect**.

Circumstances:

- Requesting BA is no longer able to provide its customers' expected energy requirements.
- Requesting BA has implemented its approved Emergency Operations Plan.

During EEA 2, RCs and requesting BAs have the following responsibilities:

2.1 **Notifying other BAs and market participants**. The requesting BA shall communicate its needs to other BAs and market participants. Upon request from the requesting BA, the respective RC shall post the declaration of the alert level, along with the name of the requesting BA on the RCIS website.

2.2 Declaration period. The requesting BA shall update its RC of the situation at a minimum of every hour until the EEA 2 is terminated. The RC shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the impacted RCs, BAs and TOPs**.**

2.3 Sharing information on resource availability. A BA with available resources shall contact the requesting BA and coordinate with the RC as appropriate.

2.4 Evaluating and mitigating Transmission limitations. The RC shall review Transmission outages and work with the TOP to see if it's possible to return the Transmission element that may relieve the Loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 BA actions. Before declaring an EEA 3, the requesting BA must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line, including quick-start and peaking units not being held for contingency reserves, regardless of cost.

2.5.2 Demand-Side Management curtailed. Initiate Demand Side Management within provisions of any applicable agreements not being held for contingency reserves.

3. EEA 3 — Inability to meet Operating Reserve requirement or Firm Load interruption is imminent or in progress.

Circumstances:

- Requesting BA is unable to meet Operating Reserve requirements and foresees a need for possible interruption of firm Load.

During EEA 3, RCs and BAs have the following responsibilities:

3.1 Continue actions from EEA 2. The RCs and the requesting BA shall continue to take all actions initiated during EEA 2.

3.2 Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement.

3.3 Declaration Period. The BA shall update its RC of the situation at a minimum of every hour until the EEA 3 is terminated. The RC shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the impacted BAs and TOPs.

3.4 Reevaluating and revising SOLs and IROLs. The RC shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the requesting BA.

Reevaluation of SOLs and IROLs shall be coordinated with other RCs and only with the agreement of the TOP whose equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the TOP whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.4.1 Requesting BA obligations. The requesting BA must agree that, upon notification from its RC of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.5 Returning to pre-Emergency conditions. Whenever energy is made available to a requesting BA such that the Transmission Systems can be returned to its pre-Emergency SOLs or IROLs condition, the requesting BA shall request the RC to downgrade the alert level.

3.5.1 Notification of other parties. Upon notification from the requesting BA that an alert has been downgraded, the RC shall notify the impacted RCs (via the RCIS), BAs and TOPs that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the requesting BA is able to meet its Load and Operating Reserve requirements, it shall request its RC to terminate the EEA**.**

0.1 Notification. The RC shall notify all other RCs via the RCIS of the termination. The RC shall also notify the impacted BAs and TOPs.

Guidelines and Technical Basis

Rationales to be added here after balloting.

Requirement R1:

Requirement R2:

Requirement R3:

Requirement R4:

Requirement R5:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Standards Committee (SC) authorized moving the SAR forward to standard development 10/17/2013.
2. SAR posted for comment 11/06/13-12/05/13.
3. ~~2.~~3.Informal posting for comment 03/28/14-04/28/14.

Description of Current Draft

This is the ~~first~~ second draft of the proposed standard and is being posted for ~~informal~~ formal stakeholder comments and initial ballot. This draft includes the modifications based on the Five-Year Review Team recommendations, comments submitted by stakeholders during the SAR comment period, comments submitted by stakeholders during the informal comment period, as well as other items identified in the SAR and applicable FERC directives from FERC Order 693.

Anticipated Actions	Anticipated Date
~~30-day Informal Comment Period~~	~~March 2014~~
45-day Formal Comment Period with Parallel Initial Ballot	June 2014
Final ballot	~~September~~ October 2014
BOT adoption	November 2014
File standard with regulatory authorities	December 2014

Effective Dates

The standard shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Initial Standard	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

Definitions of Terms Used in Standard

This section includes all newly~~-~~-defined or revised terms used in the proposed standard. -Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. -New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Energy Emergency - A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer ~~provide~~ meet its ~~customers'~~ expected ~~energy~~ Load ~~requirements~~obligations.

The proposed revisions are intended to clarify that an Energy Emergency is not necessarily limited to a Load-Serving Entity. This term, or variations of it, is also used in other standards, as indicated below. The EOP SDT is obligated to review other standards in which this term is used to determine if reliability gaps or redundancies are created by the proposed revision to the defined term. The EOP SDT has made a review of other standards in which the term "energy emergency" is used and does not believe the proposed revisions change the reliability intent of requirements or definitions.

- **BAL-002-WECC – Contingency Reserve**: This standard becomes enforceable on October 1st, 2014. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **IRO-005-3.1a — Reliability Coordination — Current Day Operations** - This standard was revised under Project 2006-06 and the reference to Energy Emergency was removed from the standard. The standard was approved by the NERC BOT and filed with FERC. NERC has requested that FERC defer action on its petition and is revising this standard under project 2014-03, TOP / IRO Revisions. This project is scheduled to be completed no later than January 31, 2015. The two standard drafting teams are coordinating the definition revision to ensure there are no redundancies.
- **MOD-004-1 — Capacity Benefit Margin:** This standard is being retired and replaced with MOD-001-2 — Modeling, Data, and Analysis — Available Transmission System Capability (NERC BOT approved February 6, 2014). The term "energy emergency" is not used in the new standard. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability to the existing approved standard.
- **INT-004-3 – Dynamic Transfers:** This standard was a revision to INT-004-2 under Project 2008-12. INT-004-3 was approved by the NERC BOT and filed with FERC. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **Defined term Emergency Request for Interchange:** This term is not used in any existing approved standard.

~~**BAL-002-WECC-2 – Contingency Reserve**~~

~~R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is: *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*~~

~~1.1. The greater of either:~~

- ~~The amount of Contingency Reserve equal to the loss of the most severe single contingency;~~

~~R1. Each Balancing Authority and each Reserve Sharing Group shall maintain a minimum amount of Contingency Reserve, except within the first sixty minutes following an event requiring the activation of Contingency Reserve, that is: *[Violation Risk Factor: High] [Time Horizon: Real-time operations]*~~

~~1.1. The greater of either:~~

- ~~The amount of Contingency Reserve equal to the loss of the most severe single contingency;~~
- ~~The amount of Contingency Reserve equal to the sum of three percent of hourly integrated Load plus three percent of hourly integrated generation.~~

~~1.2. Comprised of any combination of the reserve types specified below:~~

- ~~Operating Reserve – Spinning~~
- ~~Operating Reserve - Supplemental~~
- ~~Interchange Transactions designated by the Source Balancing Authority as Operating Reserve – Supplemental~~
- ~~Reserve held by other entities by agreement that is deliverable on Firm Transmission Service~~
- ~~A resource, other than generation or load, that can provide energy or reduce energy consumption~~
- ~~Load, including demand response resources, Demand-Side Management resources, Direct Control Load Management, Interruptible Load or Interruptible Demand, or any other Load made available for curtailment by the Balancing Authority or the Reserve Sharing Group via contract or agreement.~~
- ~~All other load, not identified above, once the Reliability Coordinator has declared an energy emergency alert signifying that firm load interruption is imminent or in progress.~~

~~1.3. Based on real-time hourly load and generating energy values averaged over each Clock Hour (excluding Qualifying Facilities covered in 18 C.F.R.§ 292.101, as addressed in FERC Order 464).~~

~~1.4 An amount of capacity from a resource that is deployable within ten minutes.~~

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Emergency Operations**
2. **Number:** **EOP-011-1**
3. **Purpose:** To mitigate the effects of operating Emergencies~~, up to and including manual Load shedding,~~ by ensuring each Transmission Operator and Balancing Authority has developed Emergency Operating Plans, and those plans are coordinated within a Reliability Coordinator Area.
4. **Applicability:**

 4.1. Functional Entities:

4.1.1 Balancing Authority

4.1.2 Reliability Coordinator

4.1.3 Transmission Operator

5. Background:

EOP-011-1 is a new standard that consolidates requirements from three existing Emergency Operations standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

The Project 2009-03 Emergency Operations Standard Drafting Team (EOP SDT) developed EOP-011-1 by considering the following inputs:

- Applicable FERC directives;
- Five Year Review Team (FYRT) recommendations;
- Independent Expert Review Panel recommendations; and
- Paragraph 81 criteria.

~~The purpose of EOP-011-1 is to mitigate the effects of operating Emergencies, up to and including manual Load shedding, by implementing Emergency Operating Plans.~~ The standard streamlines the requirements for Emergency Operations for the ~~BES~~ Bulk Electric System (BES) into a clear~~er~~ and ~~more~~ concise standard that is organized by Functional Entity~~ in order to eliminate the ambiguity in previous versions~~. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include the following elements: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]*

1.1. ~~Definition of roles~~ Roles and responsibilities to activate ~~and implement~~ the Emergency Operating Plan.

1.2. ~~Procedures, processes or strategies~~ Strategies to prepare for and mitigate Emergencies including, at a minimum:

1.2.1. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an operating Emergency;

~~**1.2.1.**~~**1.2.2.** ~~Plans to control~~Voltage Control ~~voltage~~;

~~**1.2.2.**~~**1.2.3.** ~~Processes for cancelling~~ Cancellation or recall~~ing~~ of Transmission and generation outages;

~~**1.2.3.**~~**1.2.4.** ~~Processes for~~ System reconfiguration;

~~**1.2.4.**~~**1.2.5.** ~~Processes for redispatch~~ Redispatch of generation request;

~~**1.2.5.**~~**1.2.6.** Operator-controlled ~~Manual~~ manual Load shedding plan coordinated to minimize the use of automatic Load shedding;

~~**1.2.6.**~~**1.2.7.** ~~Strategies to be used to mitigate~~Mitigation of reliability impacts of extreme weather conditions~~.~~; and

1.3. ~~A process for revising its Emergency Operating Plan to account for changes in its System~~Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities.

Rationale for Requirement R1: The EOP SDT examined the recommendation of the EOP FYRT and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment~~,~~ 1, and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Transmission Operator to create an Emergency Operating Plan.

Requirement 1 Part 1.2.~~1~~ was added to this standard for the Transmission Operator to address ~~procedures, processes or~~ strategies to prepare for and mitigate Emergencies using voltage control methods, which could include switching of capacitor and reactor banks, generator reactive output and the use of synchronous condensers.

~~The topic of manual Load shedding is included in Requirement R1 (Transmission Operator Emergency Operating Plan) and Requirement R2 (Balancing Authority Emergency Operating Plan) because this sometimes requires coordination between the Balancing Authority and Transmission Operator.~~

~~The EOP SDT added Requirement R1.3, a revision of Requirement R5 in EOP-001-2.1b, to establish a process for the Transmission Operator to revise its Emergency Operating Plan to account for changes in its System.~~

It is the EOP SDT's intent for Requirement R1 Part 1.2.6. that what is unwanted is the use manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against cascading outages or system collapse. If an entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. The EOP SDT acknowledges that, in the formulation of manual Load shedding plans, complete exclusion of Loads armed for automatic Load shedding may not be possible. Each entity should, however, evaluate their automatic Load shedding schemes and coordinate their manual plans so that overlapping use of Loads is avoided to the extent reasonably possible.

"Emergency Operating Plan" within the requirements of EOP-011-1 is not intended as a newly-defined term. It is the intent of the EOP SDT that two defined terms are being used: the defined term "Emergency" and the defined term "Operating Plan."

M1. Each Transmission Operator will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability Coordinator; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate ~~capacity~~Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]*

2.1. ~~Definition of roles~~ Roles and responsibilities to activate and implement the Emergency Operating Plan~~.~~;

2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency.

~~2.1.~~2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1;

~~2.2.~~2.4. ~~Procedures, processes or strategies~~ Strategies to prepare for and mitigate Emergencies including, at a minimum:

~~2.2.1.~~2.4.1. Generating resources in its Balancing Authority Area:

~~2.2.1.1.~~2.4.1.1. capability and availability;

~~2.2.1.2.~~2.4.1.2. fuel supply and inventory concerns;

~~2.2.1.3.~~2.4.1.3. fuel switching capabilities;

~~2.2.1.4.~~2.4.1.4. environmental constraints.

~~2.2.2.~~2.4.2. Voluntary Load reductions;

~~2.2.3.~~2.4.3. Public appeals;

~~2.2.4.~~2.4.4. ~~Governmental programs~~Requests to government agencies to implement their programs to achieve necessary energy reductions;

~~2.2.5.~~2.4.5. Reduction of internal utility energy use;

~~2.2.6.~~2.4.6. Customer fuel switching;

~~2.2.7.~~2.4.7. Use of Interruptible Load, curtailable Load and demand response;

~~2.2.8.~~2.4.8. Operator-controlled ~~Manual~~ manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and

~~2.2.9.~~2.4.9. ~~Strategies for addressing~~ Mitigation of reliability impacts of extreme weather conditions~~, if not covered by other elements of the plan~~.

~~2.3.~~2.5. ~~A process for revising its~~Strategies for coordinating Emergency Operating ~~Plan~~ Plans ~~to account for changes in its System~~with impacted Balancing Authorities and impacted Transmission Operators~~.~~

Rationale for Requirement R2: ~~The EOP SDT took~~To address the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1. The EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. EOP-011-1 ~~This~~ also establishes a separate requirement for the Balancing Authority to create its Emergency Operating Plan to address ~~capacity~~Capacity and ~~energy~~ Energy Emergencies.

If any Parts of Requirement R2 are not applicable, the Balancing Authority should note "not applicable" in their plan.

The EOP SDT retained the statement "Operator-controlled manual Load shedding," as it was in the current EOP-003-2 and is consistent with the intent of the EOP SDT.

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shedding schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R2 Part 2.4.8. is to minimize as much as possible the use manual Load shedding which is already armed for automatic load shedding. The automatic Load shedding schemes are the important backstops against cascading outages or system collapse. If an entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should evaluate their automatic Load shedding schemes and coordinate their manual plans so that any overlapping use of Loads is avoided to the extent reasonably possible.

Requirement R2 Part 2.4.8 references "coordination" – the intention is that manual and automatic systems be coordinated with each other to minimize overlap of the Loads planned to be shed in each. The reference is not intended to require coordination with other entities.

The EOP SDT retained Requirement R8 from EOP-002-3.1 and added it to the Parts in Requirement R2.

~~Manual Load shedding is included in Requirement R1 (Transmission Operator Emergency~~

M2. Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2 that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability Coordinator; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its plan was implemented in accordance with Requirement R2.

~~R3.~~ ~~Each Reliability Coordinator shall coordinate the Emergency Operating Plans of the entities in its Reliability Coordinator Area to ensure that the plans are compatible and support reliability in the Reliability Coordinator Area.~~ ~~*[Violation Risk Factor: Medium] [Time Horizon: Operations Planning]*~~

~~Rationale for R3: The EOP SDT agrees that Transmission Operators and Balancing Authorities should submit Emergency Operating plans to the Reliability Coordinator for approval in order for the Reliability Coordinator to ensure all Emergency Operating Plans in its Reliability Coordinator Area are coordinated and compatible. This requirement makes the standard applicable to the Reliability Coordinator; clearly and separately identifying the Transmission Operator, Balancing Authority and Reliability Coordinator issues as they relate to the Balancing Authority and Transmission Operator (to address Paragraph 548 of Order 693) and how it needs to be planned for on the BES by the specific Functional Entities.~~

~~"…the Commission finds the reliability coordinator is a necessary entity under EOP-001-0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity."~~

~~M3.~~ ~~The Reliability Coordinator will have, and provide upon request, evidence that could include, but is not limited to, dated review documents, electronic records or studies that it coordinated each Transmission Operator's and Balancing Authority's Emergency Operating Plans within its Reliability Coordinator Area to ensure that the plans are compatible in accordance with Requirement R3.~~

~~R4.~~R3. Each Reliability Coordinator shall approve or disapprove, with stated reasons for disapproval, Emergency Operating Plans submitted by Transmission Operators and Balancing ~~Authority~~ Authorities ~~submitted or revised Emergency Operating Plans~~ within 30 calendar days of submittal. *[Violation Risk Factor: Medium] [Time Horizon:*

Rationale for ~~R4~~R3: Since Requirements R1 and R2 both require a submittal for approval, Requirement ~~R4~~ R3 requires approval or disproval. This aligns with similar requirements in EOP-006-2, Requirement 5.1.

Operations Planning]

~~M4.~~M3. The Reliability Coordinator will have documentation, such as e-mails with receipts or registered mail receipts, that it approved or disapproved, with stated reasons for disapproval, the Transmission Operator and Balancing Authority submitted and revised Emergency Operating Plans within 30 calendar days of submittal in accordance with Requirement ~~R4~~R3.

~~R5.~~ ~~Each Transmission Operator that is experiencing an operating Emergency on its Transmission System shall communicate the Emergency and its current and projected System conditions to its Reliability Coordinator.~~ ~~*[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*~~

~~Rationale for R5: This was an existing requirement in EOP-002-3.1 for Balancing Authorities. The EOP SDT has added this as an additional requirement for Transmission Operators. The EOP SDT revised communication of "future system conditions" to "projected system conditions." The purpose of this requirement is to apprise the Reliability Coordinator of the Transmission Operator's Real-time operations preparation and planning.~~

~~**M5.** The Transmission Operator that experienced an operating Emergency on its Transmission System will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it communicated the Emergency and its current and projected System conditions to its Reliability Coordinator in accordance with Requirement R5.~~

~~**R6.**~~**R4.** ~~Each Balancing Authority that is experiencing a capacity or Energy Emergency shall communicate the Emergency and its current and projected System conditions to its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*~~

~~Rationale for R6: This was an existing requirement in EOP-002-3.1 for Balancing Authorities. The EOP SDT revised communication of "future system conditions" to "projected system conditions." This modification is intended to apprise the Reliability Coordinator of the Balancing Authority Real-time operations preparation and planning.~~

~~**M6.** The Balancing Authority that experienced a capacity or Energy Emergency will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it communicated the Emergency and its current and projected System conditions to its Reliability Coordinator in accordance with Requirement R6.~~

~~**R7.**~~**R4.** Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as ~~practicable~~practical, other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for ~~R7~~R4: The EOP SDT added the words "as soon as ~~practicable~~practical" to the requirement to point to the timeliness and to the relevancy of the Emergencies and to alleviate excessive notifications on Balancing Authorities and Transmission Operators. This was an existing requirement in EOP-002-3.1 for Balancing Authorities.

~~**M7.**~~**M4.** Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if it communicated the Balancing Authority's or

Transmission Operator's Emergency to impacted Reliability Coordinators, Balancing Authorities and Transmission Operators in accordance with Requirement ~~R7~~R4.

~~**R8.** The Balancing Authority shall request its Reliability Coordinator to declare a NERC Energy Emergency Alert after the Balancing Authority has performed the steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*~~

~~Rationale for R8: The EOP SDT placed this language in this requirement since it was found in Requirements R6.5 and R7.2 of E0P-002-3.1. The EOP SDT agrees that manual Load shedding and other actions are addressed in the Emergency Operating Plan and it is not necessary to explicitly call for Load shedding to return ACE to zero in this standard. ACE requirements for the Balancing Authority are addressed in the BAL-001 and BAL-002 standards.~~

~~**M8.** Each Balancing Authority who, after performing the steps in its Emergency Operating Plan and is unable to resolve the capacity or Energy Emergency condition, will have and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that it requested its Reliability Coordinator to declare a NERC Energy Emergency Alert in accordance with Requirement R8.~~

~~R9.~~R5. Each Reliability Coordinator that has a Balancing Authority ~~or Load-Serving Entity~~ experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate ~~a~~ an ~~NERC~~ Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for ~~R9~~R5: ~~The EOP SDT retained Requirement R8 from E0P-002-3.1. The Load-Serving Entity has the right, under Attachment 1, to request that an Energy Emergency Alert (EEA) be issued, but it does not have any requirements to do so; therefore, the EOP SDT elected to retain the Load-Serving Entity in the requirement, but not as an applicable entity. If it becomes a reliability issue, the Balancing Authority or Reliability Coordinator will call for the EEA.~~ Requirement R5 was created to address the FERC directive to have the Reliability Coordinator involved to ensure that the Energy Emergency Alert gets initiated.

~~M9.~~M5. Each Reliability Coordinator, that has had a Balancing Authority ~~or Load-Serving Entity~~ experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it initiated ~~a~~ an ~~NERC~~ Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement ~~R9~~R5.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

~~1.1.~~ As defined in the NERC Rules of Procedure, “Compliance Enforcement Authority” (CEA) means NERC or the Regional Entity in their respective roles of monitoring and enforcing compliance with the NERC Reliability Standards.

~~Regional Entity~~

1.2. Evidence Retention

The Balancing Authority, Reliability Coordinator, and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Balancing Authority shall retain the current Emergency Operating Plan, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R2, and Measure M2.

~~- The Balancing Authority shall maintain evidence of compliance since the last audit for Requirements R6 and R8 and Measures M6 and M8.~~

- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R4~~, R7~~ and ~~R9~~ R5 and Measures M3, M4~~, M7~~ and ~~M9~~M5.

- The Transmission Operator shall retain the current Emergency Operating Plan, plus each version issued since the last audit and evidence of compliance since the last audit for Requirement R1, and Measure M1.

- ~~The Transmission Operator shall maintain evidence of compliance since the last audit for Requirement R5 and Measure M5.~~

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

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Violation Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Real-time Operations, Operations Planning~~TBD~~**	**High**	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include one of the Sub-Parts 1.2.1 - 1.2.7 as applicable.	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include two of the Sub-Parts 1.2.1 - 1.2.7 as applicable.	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include three of the Sub-Parts 1.2.1 - 1.2.7 as applicable. OR The Transmission Operator failed to have a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include four or more of the Sub-Parts 1.2.1 - 1.2.7. OR The Transmission Operator failed to have a Reliability Coordinator-approved Emergency Operating Plan to

					include either Part 1.1 or Part 1.3. OR The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to maintain it.	mitigate operating Emergencies on its Transmission System. OR The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to implement it for an operating Emergency.
R2	**Real-time Operations, Operations Planning~~TBD~~**	**High**	The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity	The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but	The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity	Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to include four or more of the

			and Energy Emergencies but failed to include one of the Sub-Parts 2.4.1 – 2.4.9.	failed to include two of the Sub-Parts 2.4.1 – 2.4.9.	and Energy Emergencies but failed to include three of the Sub-Parts 2.4.1 – 2.4.9. OR The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to include either Part 2.1 or Part 2.2 or Part 2.3 or Part 2.5. OR The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy	Sub-Parts 2.4.1 – 2.4.9. OR The Balancing Authority failed to have a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. OR The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to implement it for a Capacity or

					Emergencies but failed to maintain it.	Energy Emergency.
R3	**Operations Planning~~TBD~~**	**Medium**	The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 30 days but less than or equal to 40 days.	The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 40 days but less than or equal to 50 days.	The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 50 days but less than or equal to 60 days. OR The Reliability Coordinator disapproved a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans within 30 calendar days of submittal but failed to provide the reasons for disapproval.	The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 60 days. OR The Reliability Coordinator failed to approve or disapprove, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised

						Emergency Operating Plans.
R4	**Real-time Operations~~TBD~~**	**High**	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators but did not do so as soon as practical.	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify, as soon as practical, other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators.
R5	**Real-time Operations~~TBD~~**	**High**	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to notify the other Reliability Coordinators, Balancing Authorities and Transmission	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency Alert and hold conference calls between Reliability	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an

				Operators when the alert has ended.	Coordinators as necessary to communicate System conditions.	Energy Emergency Alert and notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). OR The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency Alert and notify all Balancing Authorities and Transmission Operators in its reliability area.
~~R6~~	~~TBD~~					

~~R7~~	~~TBD~~					
~~R8~~	~~TBD~~					
~~R9~~	~~TBD~~					

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Attachment 1-EOP-011-1
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator (RC) in which it communicates the condition of a Balancing Authority (BA)~~or Load-Serving Entity in its authority~~ which is experiencing an Energy Emergency.

~~The Load-Serving Entity or Balancing Authority who requests this assistance is referred to as an "Energy Deficient Entity."~~

~~NERC recognizes that Transmission Providers are subject to obligations under FERC-approved tariffs and other agreements, and nothing in these procedures should be interpreted as changing those obligations.~~

A. General Responsibilities

1. **Initiation by ~~Reliability Coordinator~~RC.** An Energy Emergency ~~Alert~~alert (EEA) may be initiated only by a ~~Reliability Coordinator~~RC at 1) the ~~Reliability Coordinator~~RC's own request, or 2) upon the request of the ~~Energy Deficient Entity~~requesting BA.

2. **Notification**. A ~~Reliability Coordinator~~RC who declares an ~~Energy Emergency Alert~~EEA ~~should~~ shall notify all ~~Balancing Authoritie~~BAs and Transmission Operators (TOP) in its reliability area. The ~~Reliability Coordinator~~RC ~~should~~ shall also notify all other ~~Reliability Coordinator~~RCs of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between ~~Reliability Coordinator~~RCs ~~should~~ shall be held as necessary to communicate System conditions. The ~~Reliability Coordinator~~RC ~~should~~ shall also notify the other ~~Reliability Coordinator~~RCs, ~~Balancing Authoritie~~BAs and ~~Transmission Operator~~TOPs when the alert has ended.

B. ~~Energy Emergency Alert~~EEA Levels

Introduction

To ensure that all ~~Reliability Coordinator~~RCs clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established ~~three~~ four levels of ~~Energy Emergency Alert~~EEAs. The ~~Reliability Coordinator~~RCs will use these terms when explaining Energy Emergencies to each other. An ~~Energy Emergency Alert~~EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standard. T~~s.~~

~~T~~he ~~Reliability Coordinator~~RC may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

~~**1. Alert 1 — Forecast the need for an Energy Emergency.**~~

~~**Circumstances:**~~

- ~~Energy Deficient Entity foresees the need to issue alerts in the upcoming operating window and is concerned about Operating Reserves.~~

~~2~~1. ~~Alert~~ EEA ~~2~~ 1 — All available generation resources in use.

Circumstances:

- ~~Energy Deficient Entity~~Requesting BA is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Operating Reserves.

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

~~3~~2. ~~Alert 3~~EEA 2 — Load management procedures in effect.

Circumstances:

- ~~Energy Deficient Entity~~Requesting BA is no longer able to provide its customers' expected energy requirements.
- ~~Energy Deficient Entity~~Requesting BA has implemented its approved Emergency Operations Plan.

During ~~Alert 3~~EEA 2, ~~Reliability Coordinator~~RCs~~,~~ and ~~Balancing Authoritie~~requesting BAs ~~and Energy Deficient Entities~~ have the following responsibilities:

2.1 Notifying other ~~Balancing Authoritie~~BAs and market participants. The ~~Energy Deficient Entity~~requesting BA ~~should~~ shall communicate its needs to other ~~Balancing Authoritie~~BAs and market participants. Upon request from the ~~Energy Deficient Entity~~requesting BA, the respective ~~Reliability Coordinator~~RC ~~should~~ shall post the declaration of the alert level, along with the name of the ~~Energy Deficient Entity~~requesting BA ~~and, if applicable, its Balancing Authority~~ on the RCIS website.

2.2 Declaration period. The ~~Energy Deficient Entity~~requesting BA ~~should~~ shall update its ~~Reliability Coordinator~~RC of the situation at a minimum of every hour until the ~~Alert 3~~EEA 2 is terminated. The ~~Reliability Coordinator~~RC ~~should~~ shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the ~~affected~~ impacted ~~Reliability Coordinator~~RCs, ~~Balancing Authority~~BAs and ~~Transmission Providers~~TOPs**.**

2.3 Sharing information on resource availability. A ~~Balancing Authority~~BA with available resources ~~should~~ shall contact the ~~Energy Deficient Entity~~requesting BA and coordinate with the ~~Reliability Coordinator~~RC as appropriate.

2.4 Evaluating and mitigating Transmission limitations. The ~~Reliability Coordinator~~RC ~~should~~ shall review Transmission outages and work with the ~~Transmission Operator~~TOP to see if it's possible to return the Transmission element that may relieve the Loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 ~~Energy Deficient Entity~~BA actions. Before declaring an ~~Alert 4~~EEA 3, the ~~Energy Deficient Entity~~requesting BA must make use of all available resources; this includes, but is not limited to:

2.5.1 **All available generation units are on line**. All generation capable of being on line in the time frame of the Emergency is on line, including quick-start and peaking units not being held for contingency reserves, regardless of cost.

2.5.2 **~~Initiate contractually interruptible Loads and demand~~Demand- ~~-side~~ Side ~~management~~ Management curtailed**. Initiate ~~contractually interruptible retail Loads curtailed, and demand~~Demand- ~~side~~ Side ~~management~~ Management within provisions of any applicable ~~activated within provisions of the~~ agreements not being held for contingency reserves.

~~2.5.3 **Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program.~~

~~**Alert 4**~~

3. EEA 3 — Inability to meet Operating Reserve requirement or Firm Load interruption is imminent or in progress.

Circumstances:

- ~~Energy Deficient Entity~~Requesting BA is unable to meet Operating Reserve requirements and ~~foresees or~~ foresees a need for possible interruption of firm Load~~has implemented firm Load obligation interruption~~.

- During EEA 3, RCs and BAs have the following responsibilities:

3.1 Continue actions from EEA 2. The RCs and the requesting BA shall continue to take all actions initiated during EEA 2.

3.2 Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement.

~~**3.1 Continue actions from Alert 3**. The Reliability Coordinators and the Energy Deficient Entity should continue to take all actions initiated during Alert 3.~~

~~3.2~~**3.3 Declaration Period.** The ~~Energy Deficient Entity~~BA ~~should~~shall update its ~~Reliability Coordinator~~RC of the situation at a minimum of every hour until the ~~Alert 4~~EEA 3 is terminated. The ~~Reliability Coordinator~~RC ~~should~~ shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the ~~affected~~ impacted ~~Balancing Authoritie~~BAs and ~~Transmission Provider~~TOPs.

~~3.3~~**3.4 Reevaluating and revising SOLs and IROLs.** The ~~Reliability Coordinator~~RC ~~should~~ shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the ~~Energy Deficient Entity~~requesting BA. Reevaluation of SOLs and IROLs ~~should~~ shall be coordinated with other ~~Reliability Coordinator~~RCs and only with the agreement of the ~~Balancing Authority or Transmission Operator~~TOP whose equipment would be affected. SOLs and IROLs ~~should~~ shall only be revised as long as an ~~Alert 4~~EEA 3 condition exists, or as allowed by the ~~Balancing Authority or~~

~~Transmission Operator~~TOP whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

~~3.3.1~~3.4.1 ~~Energy Deficient Entity~~Requesting BA obligations. The ~~Energy Deficient Entity~~requesting BA must agree that, upon notification from its ~~Reliability Coordinator~~RC of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

~~3.4~~3.5 Returning to pre-Emergency conditions. Whenever energy is made available to a~~n~~ ~~Energy Deficient Entity~~requesting BA such that the Transmission Systems can be returned to its pre-Emergency SOLs or IROLs condition, the ~~Energy Deficient Entity~~requesting BA ~~should~~ shall ~~notify its respective~~request the ~~Reliability Coordinator~~RC ~~and~~ to downgrade the alert level.

~~3.4.1~~3.5.1 Notification of other parties. Upon notification from the ~~Energy Deficient Entity~~requesting BA that an alert has been downgraded, the ~~Reliability Coordinator~~RC ~~should~~ shall notify the ~~affected~~ impacted ~~Reliability Coordinator~~RCs (via the RCIS), ~~Balancing Authoritie~~BAs and ~~Transmission Operator~~TOPs that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the ~~Energy Deficient Entity~~requesting BA ~~believes it will be~~ is able to ~~supply its customers' energy requirements~~meet its Load and Operating Reserve requirements, it ~~should~~ shall request ~~of~~ its ~~Reliability Coordinator~~RC ~~that the EEA be terminated~~to terminate the EEA**.**

0.1 Notification. The ~~Reliability Coordinator~~RC ~~should~~ shall notify all other ~~Reliability Coordinator~~RCs via the RCIS of the termination. The ~~Reliability Coordinator~~RC ~~should~~ shall also notify the ~~affected~~ impacted ~~Balancing Authoritie~~BAs and ~~Transmission Operator~~TOPs.

Guidelines and Technical Basis

Rationales to be added here after balloting.

Requirement R1:

Requirement R2:

Requirement R3:

Requirement R4:

Requirement R5:

~~**Requirement R6:**~~

~~**Requirement R7:**~~

~~**Requirement R8:**~~

~~**Requirement R9:**~~

Implementation Plan
Project 2009-03 – Emergency Operations

Standards Involved
Approval:
EOP-011-1 - Emergency Operations

Retirements:
- EOP-001-2.1b — Emergency Operations Planning
- EOP-002-3.1 — Capacity and Energy Emergencies
- EOP-003-2— Load Shedding Plans

Prerequisite Approvals
- PRC-010-1 in Project 2008-02 – Undervoltage Load Shedding

Revisions to the NERC Glossary of Terms
The following term is proposed for revision:

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide its ~~customers'~~ expected ~~energy~~ Load requirements.

Applicable Entities
Reliability Coordinator
Balancing Authority
Transmission Operator

Conforming Changes to Other Standards
Project 2008-02 – Undervoltage Load Shedding (Requirement 1 of PRC-010): Project 2009-03 - Emergency Operations (EOP-011-1) retires EOP-003-2. Requirements R2, R4 and R7 of EOP-003-2, not being absorbed by EOP-011-1, are mapped to PRC-010-1, Requirement 1.

Effective Date
EOP-011-1 and the definition of "Energy Emergency" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard and definition shall

become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

EOP-011-1 is a consolidation of EOP-001-2.1b – Emergency Operations Planning, EOP-002-3.1 – Capacity and Energy Emergencies and EOP-003-2 – Load Shedding Plans. EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 shall retire at midnight of the day immediately prior to the effective date of EOP-011-1 in the particular jurisdiction in which the new standard is becoming effective.

NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Unofficial Comment Form

Project 2009-03 Emergency Operations

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by **August 15, 2014**.

If you have questions please contact Laura Anderson at laura.anderson@nerc.net or by telephone at 404-446-9671.

Project Page

Background Information
This posting is soliciting formal comment.

The Emergency Operations Standard Drafting Team (EOP SDT) merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 to create EOP-011-1. This re-design enables the requirements for Emergency Operations to be streamlined into a clear and concise standard that is organized by Functional Entity in order to eliminate the ambiguity in previous versions. In addition, the revisions clarify the critical requirements for Emergency Operations and apply Paragraph 81 criteria, while making the standard more results-based and address outstanding directives from FERC Order No. 693.

The EOP SDT posted an initial draft of EOP-011-1 for a 30-day informal comment period through April 28, 2014. The EOP SDT has considered feedback from the informal comment period, as well as other extensive outreach, and many of the suggested changes were incorporated into the second draft of EOP-011-1, including the following:

- The qualifying phrase “Operator-Controlled” has been added preceding “manual Load shedding” in Parts of Requirements R1 and R2. Automatic Load shedding schemes are an important backstop against cascading outages or system collapse. If an entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. The EOP SDT acknowledges that, in the formulation of manual Load shedding plans, complete exclusion of Loads armed for automatic Load shedding may not be possible. Each entity should, however, evaluate their automatic Load shedding schemes and coordinate their manual plans so that overlapping use of Loads is avoided to the extent reasonably possible.

- Requirement R3 (along with its associated Measure M3) was removed from the Standard. The EOP SDT has placed the requirement to coordinate plans on the Balancing Authority (Requirement R2, Part 2.5) and on the Transmission Operator (Requirement R1, Part 1.3).

- The EOP SDT agrees with stakeholders that Requirement R5 of EOP-011-1 draft 1 is a parallel to TOP-001-1a and removed Requirement R5 (along with its associated Measure M5) from the Standard.

The EOP SDT received several comments regarding Reliability Coordinator approval of Balancing Authority and Transmission Operator Emergency Operating Plans. Paragraph 548 of Order No. 693 directed that the Reliability Coordinator be included as an applicable entity in EOP-002, and the SDT has carefully considered how to address this directive in EOP-011-1. While plan approval by the Reliability Coordinator is not specifically required by the directive in Order No. 693, the EOP SDT believes that approval by the Reliability Coordinator reduces risk to reliability of the BES.

Other changes were made in response to comments from several stakeholders including:

- Incorporating the notification requirement of Requirement R6 of EOP-011-1 draft 1 within Requirement R2. (Requirement R6 and its associated Measure M6 was removed from the Standard).
- Replaced the words “as soon as practicable” with “as soon as practical” to communicate that timeliness is important, while balancing the concern that in an Emergency there may be a need to alleviate excessive notifications on Balancing Authorities and Transmission Operators.
- Explained in the rationale of Requirement R1 that “Emergency Operating Plan” within the requirements of EOP-011-1 is not intended to be a newly-defined Glossary term; rather, the phrase is a combination of two existing Glossary terms, “Emergency” and “Operating Plan.”
- Removed “Load-Serving Entity” from Requirement R9 of EOP-011-1 draft 1 (which has become Requirement R5 of EOP-011-1 draft 2).
- Removed “NERC” from “Energy Emergency alert.”
- Restored the previous alert levels of Attachment 1.
- In coordination with the Project 2010-14.1 BARC drafting team, the EOP SDT has revised Attachment 1 to remove “Operating Reserves” from EEA 2 and to place “Operating Reserves” in EEA 3, to align with BAL-002-2 that is being developed in that project.

Coordination with Project 2008-02 Undervoltage Load Shedding

Project 2008-02 Undervoltage Load Shedding (proposed PRC-010-1) is posted concurrently. Requirements R2, R4, and R7 in EOP-003-2 – Load Shedding Plans are proposed to be replaced by requirement R1 in the proposed PRC-010-1. Stakeholders may wish to review both projects with respect to the transition of these requirements. Both projects and their implementation plans are being closely coordinated to ensure that there is no gap or duplication of requirements created by the work of the two teams.

You do not have to answer all questions. Enter comments in simple text format. Bullets, numbers, and special formatting will not be retained.

Questions

1. Based on comments from stakeholders, the EOP SDT has added the term "Operator-Controlled" preceding the language "manual Load shedding" in Parts of Requirements R1 and R2. Do you agree with this revision? If not, please provide specific suggestions for change in the comment area.

   ☐ Yes
   ☐ No
   Comments:

2. Based on comments from a majority of stakeholders, the EOP SDT removed Requirement 3 from EOP-011-1 draft 1 and has placed the requirement on the Balancing Authority and Transmission Operator to coordinate their Emergency Operating Plans with impacted Balancing Authorities and Transmission Operators. Do you agree with this revision? If not, please provide specific suggestions for change in the comment area.

   ☐ Yes
   ☐ No
   Comments:

3. The EOP SDT received several comments regarding Reliability Coordinator approval of Balancing Authority and Transmission Operator Emergency Operating Plans. The FERC directive in Paragraph 548 or Order 693 mandates that the Reliability Coordinator be included as an applicable entity; while plan approval by the Reliability Coordinator was not a specific mandated intent, the EOP SDT believes that approval by the Reliability Coordinator reduces risk to reliability of the BES. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.

   ☐ Yes
   ☐ No
   Comments:

4. The EOP SDT has removed Requirement R5 from EOP-011-1 draft 1, as it is redundant with currently-enforceable TOP-001-1a. Do you agree with this revision? If not, please explain in the comment area below.

   ☐ Yes
   ☐ No
   Comments:

5. The EOP SDT has revised Attachment 1, removing “Operating Reserves” from EEA 2 and adding “Operating Reserves” into EEA 3. Do you agree with this change? If not, please explain in the comment area below.

   ☐ Yes
   ☐ No
   Comments:

6. Do you agree with the VRFs and VSLs in EOP-011-1? If not, please indicate which Requirement(s) and specifically what you disagree with, and provide suggestions for improvement.

   ☐ Yes
   ☐ No
   Comments:

7. If you have any other comments on this Standard that you haven’t already mentioned above, please provide them here:

   Comments:

Project 2009-03: Emergency Operations

VRF and VSL Justifications for EOP-011-1

VRF and VSL Justifications – EOP-011-1, R1	
Proposed VRF	High
NERC VRF Discussion	Developing, maintaining and implementing a Reliability Coordinator-approved Emergency Operating Plan to provide the Transmission Operator the means to mitigate operating Emergencies on the Transmission System. This is a requirement that, if violated, could directly cause or contribute to Bulk Electric System (BES) instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. Since this requirement also is in the Operations Planning time frame, it could, if violated, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures; or could hinder restoration to a normal condition. Since this is a Requirement in a planning time frame, a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation or Cascading failures; or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the Emergency Operating Plan and is consistent with Requirement R2.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-003-2 R1, which deals with Load shedding under Emergency conditions, is assigned a High VRF.

VRF and VSL Justifications – EOP-011-1, R1	
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include one of the Sub-Parts 1.2.1 - 1.2.7.
Proposed Moderate VSL	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include two of the Sub-Parts 1.2.1 - 1.2.7.
Proposed High VSL	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include three of the Sub-Parts 1.2.1 - 1.2.7. OR The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include either Part 1.1 or Part 1.3.
Proposed Severe VSL	The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include four or more of the Sub-Parts 1.2.1 - 1.2.7. OR The Transmission Operator failed to have a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.

VRF and VSL Justifications – EOP-011-1, R1	
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if the Emergency Operating Plan is not developed, maintained and implemented.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System or failing to include any of the Requirement Parts.

VRF and VSL Justifications – EOP-011-1, R2	
Proposed VRF	High
NERC VRF Discussion	Developing, maintaining and implementing a Reliability Coordinator-approved Emergency Operating Plan provides the Balancing Authority the means to mitigate Capacity and Energy Emergencies. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. Since this requirement also is in the Operations Planning time frame, it could, if violated, under emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. Since this is a requirement in a planning time frame, a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the Emergency Operating Plan and is consistent with Requirement R1.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-003-2 R1, which deals with Load shedding under Emergency conditions, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.

VRF and VSL Justifications – EOP-011-1, R2	
Proposed Lower VSL	The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to include one of the Sub-Parts 2.4.1 – 2.4.9.
Proposed Moderate VSL	The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to include two of the Sub-Parts 2.4.1 – 2.4.9.
Proposed High VSL	The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to include three of the Sub-Parts 2.4.1 – 2.4.9. OR The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to include either Part 2.1 or Part 2.2 or Part 2.3 or Part 2.5.
Proposed Severe VSL	The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to include four or more of the Sub-Parts 2.4.1 – 2.4.9. OR The Balancing Authority failed to have a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if the Emergency Operating Plan is not developed, maintained and implemented.

VRF and VSL Justifications – EOP-011-1, R2	
Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity or Energy Emergencies or failing to include any of the Requirement Parts.

VRF and VSL Justifications – EOP-011-1, R3	
Proposed VRF	Medium
NERC VRF Discussion	Approval (or disapproval with stated reasons) of a submitted or revised Emergency Operating Plan provides the Transmission Operator and Balancing Authority with a Wide Area coordination of their plans. Since this is a requirement in a planning time frame that a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control or restore the BES. However, violation of a medium-risk requirement is unlikely, under Emergency, abnormal or restoration conditions anticipated by the preparations, to lead to BES instability, separation or Cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement specifies that the Reliability Coordinator must approve or disapprove, with stated reasons for disapproval, Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans within 30 calendar days of submittal. Requirements R1 and R2 specify that the Transmission Operator and Balancing authority must develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan. Requirement R3 ties these three requirements together.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-006-2 R4, which requires the Reliability Coordinator to review neighboring Reliability Coordinator's restoration plans, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.

VRF and VSL Justifications – EOP-011-1, R3	
Proposed Lower VSL	The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 30 days, but less than or equal to 40 days.
Proposed Moderate VSL	The Reliability Coordinator-approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 40 days, but less than or equal to 50 days.
Proposed High VSL	The Reliability Coordinator-approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 50 days but less than or equal to 60 days. OR The Reliability Coordinator-disapproved a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans within 30 calendar days of submittal but failed to provide the reasons for disapproval.
Proposed Severe VSL	The Reliability Coordinator-approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 60 days. OR The Reliability Coordinator failed to approve or disapprove, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if the Reliability Coordinator failed to approve or disapprove,

VRF and VSL Justifications – EOP-011-1, R3	
in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans within the specified time frame.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to approve or disapprove, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans within the specified time frame.

VRF and VSL Justifications – EOP-011-1, R4	
Proposed VRF	High
NERC VRF Discussion	Notifying impacted Reliability Coordinators, Balancing Authorities and Transmission Operators of an Emergency helps other entities have proper situational awareness and allows them the opportunity to implement measures to mitigate the Emergency. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement specifies that the Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as practical, other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators. This relates to Requirements R1 and R2, whereby the Transmission Operator and the Balancing Authority implement their Emergency Operating Plans. These Requirements are all assigned a High VRF.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-011-1 Requirements R1, Part 1.2.1 and Requirement R2, Part 2.2, are assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority and did notify

VRF and VSL Justifications – EOP-011-1, R4	
	other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators, but did not do so as soon as practical.
Proposed Severe VSL	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority and failed to notify, as soon as practical, other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as practical, other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A	The VSL is assigned for a single instance of failing to notifying other entities as soon as practical.

VRF and VSL Justifications – EOP-011-1, R4	
Cumulative Number of Violations	

VRF and VSL Justifications – EOP-011-1, R5	
Proposed VRF	High
NERC VRF Discussion	Initiation of an Energy Emergency alert helps other entities have proper situational awareness and allows them the opportunity to implement measures to mitigate the Emergency. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement and Attachment 1 provide additional detail regarding the initiation of a potential or actual Energy Emergency. This links to Requirement R2, Part 2.3 regarding the criteria for an Energy Emergency alert. Both of these Requirements are assigned a High VRF
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-011-1 Requirement R2, Part 2.3, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area and failed to notify the other Reliability Coordinators, Balancing Authorities and Transmission Operators when the alert has ended.
Proposed High VSL	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area and failed to initiate an Energy

VRF and VSL Justifications – EOP-011-1, R5	
	Emergency alert and hold conference calls between Reliability Coordinators as necessary to communicate System conditions.
Proposed Severe VSL	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency alert and notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). OR The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency alert and notify all Balancing Authorities and Transmission Operators in its reliability area.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area and fails to initiate a an NERC Energy Emergency alert, as detailed in Attachment 1.
FERC VSL G3 Violation Severity Level Assignment Should Be	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – EOP-011-1, R5	
Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of a Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area and fails to initiate a an NERC Energy Emergency alert, as detailed in Attachment 1.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2009-03 Emergency Operations (EOP-001-2.1b, -002-3.1, and -003-2)

Consideration of Issues and Directives | July 2014

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
P 571 (S- Ref 10066 – EOP-002) "As we stated in the NOPR, neither EOP-002-2 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies. The Commission agrees with MRO that "insufficient transmission capability" could be due to various causes. The ERO should examine whether to clarify this term in the Reliability Standards development process."	FERC Order No. 693	The EOP SDT has included transmission related items to be included in the Transmission Operator's Emergency Operating Plan. These items impact transmission capability and include Requirement R1, Parts 1.2.3-1.2.5: 1.2.3. Cancellation or recall of Transmission and generation outages; 1.2.4. System reconfiguration; 1.2.5. Redispatch of generation request;
573 (S- Ref 10067 – EOP-003) "The Commission agrees with FirstEnergy that for demand-side resources to qualify as another tool for balancing authorities to use in meeting control performance and disturbance control Reliability Standards, they must meet comparable technical performance requirements as generation resource options. In response to comments from Comverge and APPA, the Commission believes that curtailable loads are adequately addressed in Requirement R6 of	FERC Order No. 693	The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT developed individual requirements for the Transmission Operator and the Balancing Authority to develop, maintain and implement Emergency Operating Plan. The requirements incorporate the applicable elements of Attachment 1 for each entity. **R1.** Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include the following elements: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **1.1.** Roles and responsibilities to activate the Emergency Operating Plan;

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
the Reliability Standard but that demand response is not covered. Demand response covers considerably more resources than interruptible load. Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements.”		**1.2.** Strategies to prepare for and mitigate Emergencies including, at a minimum: **1.2.1.** Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an operating Emergency; **1.2.2.** Voltage control; **1.2.3.** Cancellation or recall of Transmission and generation outages; **1.2.4.** System reconfiguration; **1.2.5.** Redispatch of generation request; **1.2.6.** Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; **1.2.7.** Mitigation of reliability impacts of extreme weather conditions; and **1.3.** Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities. **R2.** Each Balancing Authority shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **2.1.** Roles and responsibilities to activate the Emergency Operating Plan; **2.2.** Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency;

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1; **2.4.** Strategies to prepare for and mitigate Emergencies including, at a minimum: **2.4.1.** Generating resources in its Balancing Authority Area: **2.4.1.1.** capability and availability; **2.4.1.2.** fuel supply and inventory concerns; **2.4.1.3.** fuel switching capabilities; and **2.4.1.4.** environmental constraints. **2.4.2.** Voluntary Load reductions; **2.4.3.** Public appeals; **2.4.4.** Requests to government agencies to implement their programs to achieve necessary energy reductions; **2.4.5.** Reduction of internal utility energy use; **2.4.6.** Customer fuel switching; **2.4.7.** Use of Interruptible Load, curtailable Load and demand response; **2.4.8.** Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and **2.4.9.** Mitigation of reliability impacts of extreme weather conditions. **2.5.** Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
595 (S- Ref 10072 – EOP-003) "The Commission concludes that the Reliability Standard needs to be modified to ensure that adequate load shedding capabilities are provided so that system operators have an effective operating measure of last resort to contain system emergencies and prevent cascading. The Commission recognizes that the amount of load shedding capability required is dependent on system characteristics and therefore it may not be feasible to have a uniform nationwide load shedding capability. This, however, does not preclude a uniform nationwide criterion on the methodology for establishing load shedding capability that would specify the minimum amount of load shedding capability that should be provided based on system characteristics and conditions and the maximum amount of delay before load shedding can be implemented. The Commission directs the ERO to address the minimum load and maximum time concerns of the Commission through the Reliability Standards development process. We suggest that a review of industry best practices	FERC Order No. 693	The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT developed individual requirements for the Transmission Operator and the Balancing Authority to develop, maintain and implement Emergency Operating Plan. The requirements incorporate the applicable elements of Attachment 1 for each entity. **R1.** Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include the following elements: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **1.1.** Roles and responsibilities to activate the Emergency Operating Plan; **1.2.** Strategies to prepare for and mitigate Emergencies including, at a minimum: **1.2.1.** Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an operating Emergency; **1.2.2.** Voltage control; **1.2.3.** Cancellation or recall of Transmission and generation outages; **1.2.4.** System reconfiguration; **1.2.5.** Redispatch of generation request; **1.2.6.** Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; **1.2.7.** Mitigation of reliability impacts of extreme weather conditions; and

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
would be useful in developing nationwide critera.		**1.3.** Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities. **R2.** Each Balancing Authority shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **2.1.** Roles and responsibilities to activate the Emergency Operating Plan; **2.2.** Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency; **2.3.** Criteria to declare an Energy Emergency Alert, per Attachment 1; **2.4.** Strategies to prepare for and mitigate Emergencies including, at a minimum: **2.4.1.** Generating resources in its Balancing Authority Area: **2.4.1.1.** capability and availability; **2.4.1.2.** fuel supply and inventory concerns; **2.4.1.3.** fuel switching capabilities; and **2.4.1.4.** environmental constraints. **2.4.2.** Voluntary Load reductions; **2.4.3.** Public appeals; **2.4.4.** Requests to government agencies to implement their programs to achieve necessary energy reductions;

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		2.4.5. Reduction of internal utility energy use; **2.4.6.** Customer fuel switching; **2.4.7.** Use of Interruptible Load, curtailable Load and demand response; **2.4.8.** Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and **2.4.9.** Mitigation of reliability impacts of extreme weather conditions. **2.5.** Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.
P 597 (S- Ref 10073 – EOP-003) "As suggested by California PUC, periodic drills of simulated load shedding should involve all participants required to ensure successful implementation of load shedding plans. As such, the drills should extend beyond system operators to distribution operators and LSEs. The Reliability Standard should require periodic drills by entities subject to section 215, and require those entities to seek participation by other entities. The drills should test the readiness and functionality of the load shedding plans, including, at times, the actual deployment of personnel. Therefore the Commission disagrees with FirstEnergy that the	FERC Order No. 693	The Transmission Operator participates in Reliability Coordinator restoration drills and they will be able to shed Load with or without the Load-Serving Entity or Distribution Provider. Transmission Operators also participate in annual training required under Reliability Standard PER-005-2. NERC has launched the Risk-Based Registration (RBR) Initiative to ensure that the right entities are subject to the right set of applicable Reliability Standards, using a consistent approach to risk assessment and registration across the ERO. The goal is to develop enhanced registry criteria, including the use of thresholds and specific Reliability Standards applicability, where appropriate, to better align compliance obligations with material risk to Bulk Electric System reliability. The proposed enhancements reduce unnecessary burdens by all involved while preserving Bulk Electric System reliability and avoiding causing or exacerbating instability, uncontrolled separation, or cascading failures.

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
requirement for periodic drills of simulated load shedding should be incorporated into the new PER-005-0 Reliability Standard that is currently being drafted to address operator training.”		
P 601 (S- Ref 10074 – EOP-003) “APPA Comments are in Paragraph 598: ‘In addition, APPA states that NERC should consider requiring balancing authorities and transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners’."	FERC Order No. 693	The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT developed individual requirements for the Transmission Operator and the Balancing Authority to develop, maintain and implement Emergency Operating Plan. The requirements incorporate the applicable elements of Attachment 1 for each entity. Coordination and planning of automatic and manual Load shedding has been adequately addressed by requiring Transmission Operators and Balancing Authorities to have a Reliability Coordinator-approved Emergency Operating Plan. **R1.** Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include the following elements: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **1.1.** Roles and responsibilities to activate the Emergency Operating Plan; **1.2.** Strategies to prepare for and mitigate Emergencies including, at a minimum: **1.2.1.** Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an operating Emergency; **1.2.2.** Voltage control;

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		1.2.3. Cancellation or recall of Transmission and generation outages; **1.2.4.** System reconfiguration; **1.2.5.** Redispatch of generation request; **1.2.6.** Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; **1.2.7.** Mitigation of reliability impacts of extreme weather conditions; and **1.3.** Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities. **R2.** Each Balancing Authority shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **2.1.** Roles and responsibilities to activate the Emergency Operating Plan; **2.2.** Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency; **2.3.** Criteria to declare an Energy Emergency Alert, per Attachment 1; **2.4.** Strategies to prepare for and mitigate Emergencies including, at a minimum: **2.4.1.** Generating resources in its Balancing Authority Area: **2.4.1.1.** capability and availability; **2.4.1.2.** fuel supply and inventory concerns;

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		2.4.1.3. fuel switching capabilities; and **2.4.1.4.** environmental constraints. **2.4.2.** Voluntary Load reductions; **2.4.3.** Public appeals; **2.4.4.** Requests to government agencies to implement their programs to achieve necessary energy reductions; **2.4.5.** Reduction of internal utility energy use; **2.4.6.** Customer fuel switching; **2.4.7.** Use of Interruptible Load, curtailable Load and demand response; **2.4.8.** Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and **2.4.9.** Mitigation of reliability impacts of extreme weather conditions. **2.5.** Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.

Proposed Definitions for the NERC Glossary of Terms

Project 2009-03: Emergency Operations

The Emergency Operations Standards Drafting Team (EOP SDT) proposes revisions to a defined term in the NERC Glossary of Terms. This defined term is used in the EOP family of standards and in other standards or defined terms as discussed below.

Proposed revised definitions (redlined):

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer ~~provide~~ meet its ~~customers'~~ expected ~~energy~~ Load ~~requirements~~ obligations.

This defined term was revised to provide clarity that an Energy Emergency is not necessarily limited to a Load-Serving Entity.

This defined term, or variations of it, is also used in the instances below. The EOP SDT does not believe that the proposed revisions change the reliability intent of these standard or definitions.

- **BAL-002-WECC – Contingency Reserve**: This standard becomes enforceable on October 1st, 2014. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **IRO-005-3.1a — Reliability Coordination — Current Day Operations** - This standard was revised under Project 2006-06 and the reference to Energy Emergency was removed from the standard. The standard was approved by the NERC BOT and filed with FERC. NERC has requested that FERC defer action on its petition and is revising this standard under project 2014-03, TOP / IRO Revisions. This project is scheduled to be completed no later than January 31, 2015. The two standard drafting teams are coordinating the definition revision to ensure there are no redundancies.
- **MOD-004-1 — Capacity Benefit Margin:** This standard is being retired and replaced with MOD-001-2 — Modeling, Data, and Analysis — Available Transmission System Capability (NERC BOT approved February 6, 2014). The term "energy emergency" is not used in the new standard. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability to the existing approved standard.
- **INT-004-3 – Dynamic Transfers:** This standard was a revision to INT-004-2 under Project 2008-12. INT-004-3 was approved by the NERC BOT and filed with FERC. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.

- **Defined term Emergency Request for Interchange:** This term is not used in any existing approved standard.

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Project 2009-03 - Emergency Operations

Mapping Document

Project Purpose

The Emergency Operations Five-Year Review Team (EOP FYRT) was appointed by the Standards Committee Executive Committee on April 22, 2013. The EOP FYRT has reviewed the following Emergency Operations standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 to decide if revisions are needed in the scope of this project in relation to P81 and FERC directives. This project is a comprehensive review of this set of EOP standards to ensure that the requirements are clear and unambiguous. Many of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process, and the standards were due for a comprehensive review. Suggestions for improvement, possible consolidation and for requirements to be considered for retirement under Paragraph 81 have been submitted by stakeholders, other drafting teams and FERC staff.

On October 17, 2013 the Standards Committee accepted the recommendations of the EOP FYRT and appointed a drafting team to implement the recommendations and begin formal development. The Standards Committee further authorized the posting of the Standard Authorization Request (SAR) developed by the EOP FYRT.

Project 2009-03 – Emergency Operations (EOP-011-1) is being coordinated with Project 2008-02 – Undervoltage Load Shedding, which proposes to retire EOP-003-2 Requirements R2, R4, and R7 since these requirements are proposed to be covered by PRC-010-1, Requirement R1; this translation is illustrated in this document and will also be referenced in Project 2008-02's mapping document. The project schedules and implementation plans for these two projects are being closely coordinated to ensure that no gaps or duplication will result from the products developed by the two drafting teams.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Roles and responsibilities to activate the Emergency Operating Plan. 2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency; 2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1; 2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum: 2.4.1. Generating resources in its Balancing Authority Area: 2.4.1.1. capability and availability;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.4.1.2. fuel supply and inventory concerns; 2.4.1.3. fuel switching capabilities; and 2.4.1.4. environmental constraints. 2.4.2. Voluntary Load reductions; 2.4.3. Public appeals; 2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.4.5. Reduction of internal utility energy use; 2.4.6. Customer fuel switching; 2.4.7. Use of Interruptible Load, curtailable Load and demand response; 2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and 2.4.9. Mitigation of reliability impacts of extreme weather conditions. 2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.
		EOP-011-1, R1

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R2. Each Transmission Operator and Balancing Authority shall: **R2.1.** Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity. **R2.2.** Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system. **R2.3.** Develop, maintain, and implement a set of plans for load shedding	Translated to EOP-011-1, Emergency Operations.	R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 1.1. Roles and responsibilities to activate the Emergency Operating Plan; 1.2. Strategies to prepare for and mitigate Emergencies including, at a minimum: 1.2.1. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an operating Emergency; 1.2.2. Voltage control; 1.2.3. Cancellation or recall of Transmission and generation outages; 1.2.4. System reconfiguration; 1.2.5. Redispatch of generation request;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.6. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 1.2.7. Mitigation of reliability impacts of extreme weather conditions; and 1.3. Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities. **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Roles and responsibilities to activate the Emergency Operating Plan. 2.2. Notification to the Reliability Coordinator, to include current and projected System conditions,

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		when experiencing a Capacity Emergency or Energy Emergency; 2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1; 2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum: 2.4.1. Generating resources in its Balancing Authority Area: 2.4.1.1. capability and availability; 2.4.1.2. fuel supply and inventory concerns; 2.4.1.3. fuel switching capabilities; and 2.4.1.4. environmental constraints. 2.4.2. Voluntary Load reductions; 2.4.3. Public appeals; 2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.4.5. Reduction of internal utility energy use; 2.4.6. Customer fuel switching; 2.4.7. Use of Interruptible Load, curtailable Load and demand response;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and 2.4.9. Mitigation of reliability impacts of extreme weather conditions. 2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.
R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include: **R3.1.** Communications protocols to be used during emergencies. **R3.2.** A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions.	Translated to EOP-011-1, Emergency Operations; Retired R3.1 under Criteria A and B7 of Paragraph 81 guidelines; Retired R3.4 under Criteria A and B1 of Paragraph 81 guidelines.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 1.1. Roles and responsibilities to activate the Emergency Operating Plan; 1.2. Strategies to prepare for and mitigate Emergencies including, at a minimum:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R3.3. The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities. **R3.4.** Staffing levels for the emergency.		1.2.1. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an operating Emergency; 1.2.2. Voltage control; 1.2.3. Cancellation or recall of Transmission and generation outages; 1.2.4. System reconfiguration; 1.2.5. Redispatch of generation request; 1.2.6. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 1.2.7. Mitigation of reliability impacts of extreme weather conditions; and 1.3. Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities. **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Roles and responsibilities to activate the Emergency Operating Plan. 2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency; 2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1; 2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum: 2.4.1. Generating resources in its Balancing Authority Area: 2.4.1.1. capability and availability; 2.4.1.2. fuel supply and inventory concerns; 2.4.1.3. fuel switching capabilities; and 2.4.1.4. environmental constraints. 2.4.2. Voluntary Load reductions; 2.4.3. Public appeals;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.4.5. Reduction of internal utility energy use; 2.4.6. Customer fuel switching; 2.4.7. Use of Interruptible Load, curtailable Load and demand response; 2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and 2.4.9. Mitigation of reliability impacts of extreme weather conditions. 2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators. **<u>Retirements:</u>** **Requirement R3.1** • Meets Criterion B7 and Criterion A of Paragraph 81; • Covered by EOP-001-2.1b Requirement R4 in Attachment 1 (proposed Requirements R1 and R2 in EOP-011-1); and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		• COM-001 and COM-002 are descriptive in the identification of protocols to use and, thus, adequately cover the generic reference. **Requirement R3.2** • Meets Criterion B7 and Criterion A of Paragraph 81; • Covered by EOP-001-2.1b Requirement R4 in Attachment 1 (proposed Requirements R1 and R2 in EOP-011-1); and • Load reduction within timelines is covered by BAL-002 Requirement R2. **Requirement R3.4** • Meets Criterion B1 of Paragraph 81; and • Staffing levels are administrative in nature.
R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 1.1. Roles and responsibilities to activate the Emergency Operating Plan; 1.2. Strategies to prepare for and mitigate Emergencies including, at a minimum: 1.2.1. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an operating Emergency; 1.2.2. Voltage control; 1.2.3. Cancellation or recall of Transmission and generation outages; 1.2.4. System reconfiguration; 1.2.5. Redispatch of generation request; 1.2.6. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 1.2.7. Mitigation of reliability impacts of extreme weather conditions; and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.3. Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities. **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Roles and responsibilities to activate the Emergency Operating Plan. 2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency; 2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1; 2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.4.1. Generating resources in its Balancing Authority Area: 2.4.1.1. capability and availability; 2.4.1.2. fuel supply and inventory concerns; 2.4.1.3. fuel switching capabilities; and 2.4.1.4. environmental constraints. 2.4.2. Voluntary Load reductions; 2.4.3. Public appeals; 2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.4.5. Reduction of internal utility energy use; 2.4.6. Customer fuel switching; 2.4.7. Use of Interruptible Load, curtailable Load and demand response; 2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and 2.4.9. Mitigation of reliability impacts of extreme weather conditions.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.
R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 1.1. Roles and responsibilities to activate the Emergency Operating Plan; 1.2. Strategies to prepare for and mitigate Emergencies including, at a minimum: 1.2.1. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an operating Emergency; 1.2.2. Voltage control;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.3. Cancellation or recall of Transmission and generation outages; 1.2.4. System reconfiguration; 1.2.5. Redispatch of generation request; 1.2.6. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 1.2.7. Mitigation of reliability impacts of extreme weather conditions; and 1.3. Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities. **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.1. Roles and responsibilities to activate the Emergency Operating Plan. 2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency; 2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1; 2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum: 2.4.1. Generating resources in its Balancing Authority Area: 2.4.1.1. capability and availability; 2.4.1.2. fuel supply and inventory concerns; 2.4.1.3. fuel switching capabilities; and 2.4.1.4. environmental constraints. 2.4.2. Voluntary Load reductions; 2.4.3. Public appeals; 2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.4.5. Reduction of internal utility energy use;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.4.6. Customer fuel switching; 2.4.7. Use of Interruptible Load, curtailable Load and demand response; 2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and 2.4.9. Mitigation of reliability impacts of extreme weather conditions. 2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.
R6. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable: **R6.1.** The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems.	Retired under Criteria B6 and B7 of P81 guidelines.	**<u>Retirements</u>** **Requirement R6.1** • Meets Criterion B7 of Paragraph 81; and • Redundant with COM-001. **Requirement R6.2** • Meets Criterion B6 of Paragraph 81; • Speaks to an action to be taken during capacity issues that is not feasible in accomplishing; and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R6.2. The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used. **R6.3.** The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.) **R6.4.** The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.		• Transaction arrangements are a commercial practice. **Requirement R6.3** • Meets Criterion B7 of Paragraph 81; and • Covered by EOP-001-2.1b Requirement R4 in Attachment 1 (proposed Requirements R1 and R2 in EOP-011-1). **Requirement R6.4** • Meets Criterion A of Paragraph 81; and • Does not provide benefit to the reliability of the BES.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.	Retired under Criteria A and B7 of P81 guidelines.	**Retired – redundant with PER-001, R1 with respect to the Balancing Authority and IRO-001-1.1, Requirement R3 for the Reliability Coordinator.**
R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan to reduce risks to the interconnected system.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Roles and responsibilities to activate the Emergency Operating Plan. 2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1; 2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum: 2.4.1. Generating resources in its Balancing Authority Area: 2.4.1.1. capability and availability; 2.4.1.2. fuel supply and inventory concerns; 2.4.1.3. fuel switching capabilities; and 2.4.1.4. environmental constraints. 2.4.2. Voluntary Load reductions; 2.4.3. Public appeals; 2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.4.5. Reduction of internal utility energy use; 2.4.6. Customer fuel switching; 2.4.7. Use of Interruptible Load, curtailable Load and demand response; 2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.4.9. Mitigation of reliability impacts of extreme weather conditions. 2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.
R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Roles and responsibilities to activate the Emergency Operating Plan. 2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency; 2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum: 2.4.1. Generating resources in its Balancing Authority Area: 2.4.1.1. capability and availability; 2.4.1.2. fuel supply and inventory concerns; 2.4.1.3. fuel switching capabilities; and 2.4.1.4. environmental constraints. 2.4.2. Voluntary Load reductions; 2.4.3. Public appeals; 2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.4.5. Reduction of internal utility energy use; 2.4.6. Customer fuel switching; 2.4.7. Use of Interruptible Load, curtailable Load and demand response; 2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and 2.4.9. Mitigation of reliability impacts of extreme weather conditions.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.
R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Roles and responsibilities to activate the Emergency Operating Plan. 2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency; 2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1; 2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.4.1. Generating resources in its Balancing Authority Area: 2.4.1.1. capability and availability; 2.4.1.2. fuel supply and inventory concerns; 2.4.1.3. fuel switching capabilities; and 2.4.1.4. environmental constraints. 2.4.2. Voluntary Load reductions; 2.4.3. Public appeals; 2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.4.5. Reduction of internal utility energy use; 2.4.6. Customer fuel switching; 2.4.7. Use of Interruptible Load, curtailable Load and demand response; 2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and 2.4.9. Mitigation of reliability impacts of extreme weather conditions.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.
R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Roles and responsibilities to activate the Emergency Operating Plan. 2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency; 2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1; 2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.4.1. Generating resources in its Balancing Authority Area: 2.4.1.1. capability and availability; 2.4.1.2. fuel supply and inventory concerns; 2.4.1.3. fuel switching capabilities; and 2.4.1.4. environmental constraints. 2.4.2. Voluntary Load reductions; 2.4.3. Public appeals; 2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.4.5. Reduction of internal utility energy use; 2.4.6. Customer fuel switching; 2.4.7. Use of Interruptible Load, curtailable Load and demand response; 2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and 2.4.9. Mitigation of reliability impacts of extreme weather conditions.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.
R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: **R6.1.** Loading all available generating capacity. **R6.2.** Deploying all available operating reserve. **R6.3.** Interrupting interruptible load and exports. **R6.4.** Requesting emergency assistance from other Balancing Authorities. **R6.5.** Declaring an Energy Emergency through its Reliability Coordinator; and **R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Roles and responsibilities to activate the Emergency Operating Plan. 2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency; 2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1; 2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.4.1. Generating resources in its Balancing Authority Area: 2.4.1.1. capability and availability; 2.4.1.2. fuel supply and inventory concerns; 2.4.1.3. fuel switching capabilities; and 2.4.1.4. environmental constraints. 2.4.2. Voluntary Load reductions; 2.4.3. Public appeals; 2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.4.5. Reduction of internal utility energy use; 2.4.6. Customer fuel switching; 2.4.7. Use of Interruptible Load, curtailable Load and demand response; 2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and 2.4.9. Mitigation of reliability impacts of extreme weather conditions.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.
R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall: **R7.1.** Manually shed firm load without delay to return its ACE to zero; and **R7.2.** Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Roles and responsibilities to activate the Emergency Operating Plan. 2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency; 2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1; 2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.4.1. Generating resources in its Balancing Authority Area: 2.4.1.1. capability and availability; 2.4.1.2. fuel supply and inventory concerns; 2.4.1.3. fuel switching capabilities; and 2.4.1.4. environmental constraints. 2.4.2. Voluntary Load reductions; 2.4.3. Public appeals; 2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.4.5. Reduction of internal utility energy use; 2.4.6. Customer fuel switching; 2.4.7. Use of Interruptible Load, curtailable Load and demand response; 2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and 2.4.9. Mitigation of reliability impacts of extreme weather conditions.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.
R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R5** R5. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate an Energy Emergency Alert, as detailed in Attachment 1. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration transmission Service from designated Network Resources) as permitted in its transmission tariff: **R9.1**. The deficient Load-Serving Entity shall request its Reliability Coordinator to	Retired per P81 – this is addressed in NAESB tagging specification.	**LSEs have no Real-time reliability functionality with respect to EEAs.** Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts." **R9.2.** The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed. **R9.3.** The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7. **R9.4.** The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.		and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.
Attachment 1 **2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy.	Translated to EOP-011-1, Attachment 1.	**Attachment 1** **3.1 Operating Reserves.** Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.		or has initiated Emergency assistance through its Operating Reserve sharing program. In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 1.1. Roles and responsibilities to activate the Emergency Operating Plan; 1.2. Strategies to prepare for and mitigate Emergencies including, at a minimum: 1.2.1. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an operating Emergency; 1.2.2. Voltage control; 1.2.3. Cancellation or recall of Transmission and generation outages;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.4. System reconfiguration; 1.2.5. Redispatch of generation request; 1.2.6. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 1.2.7. Mitigation of reliability impacts of extreme weather conditions; and 1.3. Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities. **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Roles and responsibilities to activate the Emergency Operating Plan.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency; 2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1; 2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum: 2.4.1. Generating resources in its Balancing Authority Area: 2.4.1.1. capability and availability; 2.4.1.2. fuel supply and inventory concerns; 2.4.1.3. fuel switching capabilities; and 2.4.1.4. environmental constraints. 2.4.2. Voluntary Load reductions; 2.4.3. Public appeals; 2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.4.5. Reduction of internal utility energy use; 2.4.6. Customer fuel switching;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.4.7. Use of Interruptible Load, curtailable Load and demand response; 2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and 2.4.9. Mitigation of reliability impacts of extreme weather conditions. 2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.
R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.	EOP-003-2, R2 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design.	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design. **1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, auto-reclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 1.1. Roles and responsibilities to activate the Emergency Operating Plan; 1.2. Strategies to prepare for and mitigate Emergencies including, at a minimum: 1.2.1. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an operating Emergency; 1.2.2. Voltage control; 1.2.3. Cancellation or recall of Transmission and generation outages; 1.2.4. System reconfiguration; 1.2.5. Redispatch of generation request; 1.2.6. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 1.2.7. Mitigation of reliability impacts of extreme weather conditions; and

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.3. Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities. **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Roles and responsibilities to activate the Emergency Operating Plan. 2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency; 2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1; 2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum:

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.4.1. Generating resources in its Balancing Authority Area: 2.4.1.1. capability and availability; 2.4.1.2. fuel supply and inventory concerns; 2.4.1.3. fuel switching capabilities; and 2.4.1.4. environmental constraints. 2.4.2. Voluntary Load reductions; 2.4.3. Public appeals; 2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.4.5. Reduction of internal utility energy use; 2.4.6. Customer fuel switching; 2.4.7. Use of Interruptible Load, curtailable Load and demand response; 2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and 2.4.9. Mitigation of reliability impacts of extreme weather conditions.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.
R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels.	EOP-003-2, R4 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design. EOP-003-2, R4 is inherently embedded in PRC-010-1, R1, Part 1.1. The specific items noted are described in PRC-010-1's Guidelines and Technical Basis.	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design. **1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems,

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		including, but not limited to, transmission line protection, auto-reclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.	Retired under Criteria A and B7 of Paragraph 81.	**Redundant with R1 of EOP-003-2, which maps to EOP-011-1, R1.** Requirement R5 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement.
R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency	Retired under Criteria and B7 of Paragraph 81.	**Redundant with R1 of EOP-003-2, which maps to EOP-011-1, R1.**

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
load shedding, the Transmission Operator or Balancing Authority shall shed additional load.		Requirement R6 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R6 speaks of two events that must be valid to tell the BA or TOP to shed more Load. .
R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions.	EOP-003-2, R7 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design. EOP-003-2, R7 is inherently embedded in PRC-010-1, R1, Part 1.2. The specific items noted are described in PRC-010-1's	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design. **1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
	Guidelines and Technical Basis.	capabilities and other protection and control systems, including, but not limited to, transmission line protection, auto-reclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 1.1. Roles and responsibilities to activate the Emergency Operating Plan;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2. Strategies to prepare for and mitigate Emergencies including, at a minimum: 1.2.1. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an operating Emergency; 1.2.2. Voltage control; 1.2.3. Cancellation or recall of Transmission and generation outages; 1.2.4. System reconfiguration; 1.2.5. Redispatch of generation request; 1.2.6. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; 1.2.7. Mitigation of reliability impacts of extreme weather conditions; and 1.3. Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities. **EOP-011-1, R2**

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning] 2.1. Roles and responsibilities to activate the Emergency Operating Plan. 2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency; 2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1; 2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum: 2.4.1. Generating resources in its Balancing Authority Area: 2.4.1.1. capability and availability; 2.4.1.2. fuel supply and inventory concerns; 2.4.1.3. fuel switching capabilities; and

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.4.1.4. environmental constraints. 2.4.2. Voluntary Load reductions; 2.4.3. Public appeals; 2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.4.5. Reduction of internal utility energy use; 2.4.6. Customer fuel switching; 2.4.7. Use of Interruptible Load, curtailable Load and demand response; 2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and 2.4.9. Mitigation of reliability impacts of extreme weather conditions. 2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.

Technical Justification
EOP-011-1 Emergency Operations and Planning

Background and Rationale for revisions of EOP-001-2.1b, EOP-002-3.1 and EOP-003-2

Purpose

The purpose of EOP-011-1 is to mitigate the effects of operating Emergencies, up to and including manual Load shedding, by implementing Emergency Operating Plans. The standard streamlines the requirements for Emergency Operations for the BES into a clear and concise standard that is organized by Functional Entity in order to eliminate ambiguity. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

The requirements of the proposed EOP-011-1 reliability standard support the following Reliability Principles:

> Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
>
> The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
>
> Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
>
> Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

EOP-011-1 consolidates requirements from three existing Emergency Operations standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2. The table *Elements for Consideration in Development of Emergency Plans* from Attachment 1 of EOP-001-2.1b were considered by the EOP SDT and incorporated into the requirements of proposed EOP-011-1.

The Project 2009-03 Emergency Operations Standard Drafting Team (EOP SDT) developed EOP-011-1 by considering the following inputs:

- Applicable FERC directives;
- Five Year Review Team (FYRT) recommendations;
- Independent Expert Review Panel recommendations; and
- Paragraph 81 criteria.

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NERC

History and Inputs to Project 2009-03 Emergency Operations

Periodic Review of EOP Standards

The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every 10 years, or once every five years for any Reliability Standard approved by the American National Standards Institute as an American National Standard.[1] The Emergency Operations Five-Year Review Team (EOP FYRT) was appointed by the Standards Committee Executive Committee on April 22, 2013. The EOP FYRT reviewed the following Emergency Operations standards: EOP-001-2.1b (Emergency Operations Planning), EOP-002-3.1 (Capacity and Energy Emergencies) and EOP-003-2 (Load Shedding Plans) to determine if the standards should be retained, retired or if revisions were needed in the scope of this project in relation to P81 criteria, Independent Expert report and FERC directives.

The scope of the review included consideration of recommendions from the Industry Expert Review Panel report, Paragraph 81 recommendations and criteria, and outstanding FERC Order No. 693 directives, as well as industry comments. The EOP FYRT posted its draft recommendations to revise the standards for stakeholder comment. After reviewing stakeholder comments, the EOP FYRT submitted its final recommendations to the Standards Committee, along with a Standard Authorization Request (SAR). This SAR replaces an earlier SAR, and the new SAR provided the scope for the work of Project 2009-03. The EOP SDT implemented the FYRT recommendations into proposed reliability standard EOP-011-1.

Industry Expert Report2

In 2013 NERC assembled a panel of Industry Experts (the IERP) to review all reliability standards and provide recommendations for consideration in the transition of NERC standards to steady state. For the Emergency Operations and Planning reliability standards, the Industry Experts made the following recommendations:

- EOP-001-2.1b, R6 - P81. Duplicative of R4 and the Attachment
- EOP-002-3.1, R2 - P81. Duplicative - requirement to take action is in R1.
- EOP-002-3.1, R3 - P81. Duplicative of what is required to be in the plan under Attachment 1 of EOP-001.
- EOP-002-3.1, R6 -P81. Duplicative of BAL standards to meet CPS and DCS
- EOP-002-3.1, R9 - P81. This is a market (tariff) issue.
- EOP-003-2, R2 - P81. Duplicative of PRC-010 and TPL standards
- EOP-003-2, R4 - P81. Duplicative of PRC-010 and TPL standards
- EOP-003-2, R5 - P81. Duplicative of R1 and also covered under standards for TOP (TOP-002-3)
- EOP-003-2, R6 - P81. Duplicative; an entity does the same actions as when not islanded.

[1] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf

[2] NERC Standards Independent Expert Review Project, An Independent Review by Industry Experts, posted at http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf

- EOP-003-2, R7 - P81. Duplicative of PRC-010 R1

As part of the EOP Five-Year Review process, the EOP FYRT evaluated these recommendations and generally agrees with them, with exceptions and further considerations for the standard drafting team, as noted below:

- EOP-001-2.1b - the EOP FYRT concurred with the recommendation to retire R6 in accordance with the applicable Paragraph 81 criteria (Requirements 6.1 and 6.3 under Criterion B7; Requirement R6.2 under Criterion B6; and Requirement R6.4 under Criterion A). In addition, the EOP FYRT also recommended that the future EOP SDT take into consideration retiring Requirements R3.1 under Criterion B7, Requirement R3.2 under Criterion B7 and Criterion A, and Requirement R3.4 under Criterion B1 of Paragraph 81. The EOP FYRT further recommended revising and merging EOP-001-2.b and EOP-002-3.1 into a single standard; revising Requirements R1, R2 and R5 and reviewing Attachment 1.
- EOP-002-3.1 - in addition to Requirements R6 and R9, the EOP FYRT recommended retiring Requirements R1 under Criterion B7 of Paragraph 81. The EOP FYRT further recommended that the future EOP SDT consider revising and merging EOP-001-2.b and EOP-002-3.1 into a single standard, which would include a revision to Requirement R3 and Attachment 1.
- EOP-003-2 - the EOP FYRT recommended Requirements R2, R4 and R7 be moved to PRC-010-0 and revised in accordance with the other requirements in that standard. In addition to merging EOP-001-2.1b with EOP-002-3.1, the EOP FYRT recommended the future EOP SDT consider merging EOP-003-2, EOP-001-1-2.1b and EOP-002-3.1 into a single standard.

Paragraph 81[3]

For a reliability standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy both: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B (identifying criteria). In addition, for each reliability standard requirement proposed for retirement or modification, the data and reference points of Criterion C should be considered for making a more informed decision.

Paragraph 81 recommendations from the Independent Experts and Industry were reviewed and the EOP SDT incorporated those into the development of EOP-011-1.

FERC Directives

In the development of the proposed EOP-011-1 reliability standard, the EOP SDT addressed the outstanding FERC directives in Order No. 693 related to Emergency Operations and planning4. Briefly, the directives applicable to each standard are listed below:

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[3] NERC – Paragraph 81 Criteria posted at http://www.nerc.com/pa/stand/project%20200812%20coordinate%20interchange%20standards%20dl/paragraph_81_criteria.pdf

[4] Outstanding FERC Order 693 directives listing related to Emergency Operations posted at Project 2009-03 Directives.xlsx

EOP-001-1 Emergency Operations Planning:

- Include reliability coordinators as an applicable entity.
- Consider Southern California Edison's and Xcel's suggestions in the standard development process.
- Clarify that the 30-minute requirement in requirement R2 to state that Load shedding should be capable of being implemented as soon as possible but no more than 30 minutes.
- Includes definitions of system states (e.g. normal, alert, emergency), criteria for entering into these states. And the authority that will declare them.
- Consider a pilot program (field test) for the system states proposal.
- Clarifies that the actual emergency plan elements, and not the "for consideration" elements of Attachment 1, should be the basis for compliance.

EOP-002-2 Capacity and Energy Emergencies:

- Address emergencies resulting not only from insufficient generation but also insufficient.
- Transmission capability, particularly as it affects the implement of the capacity and energy
- Emergency plan.
- Include all technically feasible resource options, including demand response and generation resources.
- Ensure the TLR procedure is not used to mitigate actual IROL violations.

EOP-003-1 Load Shedding Plans:

- Develop specific minimum Load shedding capability that should be provided and the maximum amount of delay before Load shedding can be implemented based on overarching nationwide criteria that take into account system characteristics.
- Require periodic drills of simulated Load shedding.
- Suggest a review of industry best practices in determining nationwide criteria.
- Consider comments from APPA and ISO-NE in the standards development process.

Rationales for Requirements

Proposed reliability standard EOP-011-1 merges EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 into a single standard applicable to the following functional entities:

- Balancing Authority
- Reliability Coordinator
- Transmission Operator

Requirement R1:

The EOP SDT examined the recommendation of the EOP FYRT and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT identified that in Attachment 1 there are elements that would not relate to the Transmission Operator and removed them from this requirement. These elements were listed in the original standard and have been retained in this standard. This also establishes a requirement for the Transmission Operator to create its Emergency Operating Plan to address capacity and energy Emergencies.

Requirement R2:
As with Requirement R1, the EOP SDT took the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1 as it relates to the Balancing Authority. The EOP SDT identified that in Attachment 1 there are elements that would not relate to the Balancing Authority and removed them from this requirement. These elements were listed in the original standard and have been retained in this standard. This also establishes a requirement for the Balancing Authority to create its Emergency Operating Plan to address capacity and energy Emergencies.

Requirement R3:
The EOP SDT agrees that Transmission Operators and Balancing Authorities should submit Emergency Operating plans to the Reliability Coordinator for approval in order for the Reliability Coordinator to ensure all Emergency Operating Plans in its Reliability Coordinator Area exist. The EOP SDT also has created this requirement so that it is similar in structure to the EOP-006-2, Requirement 5.1. The Requirement reflects the directive of the Federal Energy Regulator Commission to have the Reliability Coordinator involved in the Operating Plans of the Transmission Operator and Balancing Authority.

"…the Commission finds the reliability coordinator is a necessary entity under EOP-001-0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity."

Requirement R4:
The EOP SDT added the words "as soon as practical" to the requirement to point to the timeliness and to the relevancy of the Emergencies and to alleviate excessive notifications on Balancing Authorities and Transmission Operators. This was an existing requirement in EOP-002-3.1 for Balancing Authorities.

Requirement R5:
The EOP SDT retained Requirement R8 from E0P-002-3.1. The Load-Serving Entity has the right, under Attachment 1, to request that an Energy Emergency Alert (EEA) be issued, but it does not have any requirements to do so; therefore, the EOP SDT elected to remove the Load-Serving Entity in the requirement. The EOP SDT also ensured Requirement R5 was created to address the FERC directive to have the Reliability Coordinator involved to ensure that the Energy Emergency Alert gets initiated.

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Emergency Operations (EOP-001-3, EOP-002-4, EOP-003-3)		
Date Submitted:	October 17, 2013		
SAR Requester Information			
Name:	David McRee, Chair EOP Five-Year Review Team (FYRT)		
Organization:	Duke Energy		
Telephone:	(704) 382-9841	E-mail:	David.McRee@duke-energy.com
SAR Type (Check as many as applicable)			
☐ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
This SAR will address the Five-Year Review requirement for these standards.
Purpose or Goal (How does this request propose to address the problem described above?):
To improve the quality, relevance, and clarity of the standards. Also bring the standards into the Results Based Standards format.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
To increase the effectiveness of the three standards in their ability to ensure reliability of the BES.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The EOP SDT will consider the comments received from the EOP Five Year Review Team (FYRT), which includes consideration of industry comments and the report from the Industry Expert Review Panel. Recommendations for consideration are: • Modify the requirements and attachments to improve their clarity and measurability, while removing ambiguity • Move and/or streamline requirements • Eliminate requirements based on P81 criteria • Coordinate with Project 2008-02 UVLS to eliminate duplicative requirements • Apply Paragraph 81 criteria and recommendations from Independent Expert Review Panel on standards EOP-001, -002, and -003. To ensure a seamless transition from the EOP FYRT to the future EOP SDT, the EOP FYRT recommends the inclusion of interested EOP FYRT members to participate on the EOP SDT. In addition, the EOP FYRT should provide a high-level overview of their recommendations as a formal kick-off to the future EOP SDT meetings.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
See the attached Five-Year Review templates of the three standards, consideration of comments, issues and directives list, redlined standards (reflecting deletions), and the Industry Experts' anyalsis.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☒ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

Reliability Functions	
☒ Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐ Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐ Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐ Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐ Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐ Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐ Transmission Owner	Owns and maintains transmission facilities.
☒ Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐ Distribution Provider	Delivers electrical energy to the End-use customer.
☐ Generator Owner	Owns and maintains generation facilities.
☒ Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐ Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐ Market Operator	Interface point for reliability functions with commercial functions.
☒ Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards

Related Standards	
Standard No.	**Explanation**
BAL-001-0.1a	Real Power Balancing Control Performance
BAL-002-01	Disturbance control standard
BAL-002-WECC	Regional Contingency Reserve standard
COM-001-1.1	Telecommunications
COM-002-2	Communications and Coordination
PRC-010-0	Planning for Undervoltage Load shedding
PER-005-1	Training

Related SARs	
SAR ID	**Explanation**
	None

Regional Variances	
Region	**Explanation**
ERCOT	

Regional Variances	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

Five-Year Review Template – EOP-001-2.1b

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-001-2.1b Emergency Operations Planning
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111, ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered “Yes” to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:
   Requirement R3:

- Requirement R3.1 should be covered by EOP-001-2.1b Requirement R4 in Attachment 1 (notifications that should be included in the plan are identified). COM-001 and COM-002 are descriptive in the identification of protocols to use and, thus, adequately cover the generic reference. With the recommended revision to Attachment 1 of EOP-001-2.1b, along with COM-001 and COM-002 generic reference, Requirement R3.1 would meet Criterion B7 as redundant, as well as Criterion A (Requirement R3.1 does little, if anything, to benefit or protect the reliable operation of the BES) of Paragraph 81 and should be retired.
- Requirement R3.2 should be covered by EOP-001-2.1b Requirement R4 in Attachment 1, which lists the actions to take during capacity situations specified in the plan. Load reduction within timelines is covered in BAL-002 Requirement R2. With the recommended revision of EOP-001 Requirement R4, Requirement R3.2 would meet Criterion B7 as redundant, as well as Criterion A (R3.1 does little, if anything, to benefit or protect the reliable operation of the BES) of Paragraph 81 and should be retired.
- Requirement R3.4 meets Paragraph 81 Criterion B1; staffing levels are administrative in nature and would result in an increase in efficiency in the ERO compliance program (it is a simple check off during an audit). Requirement R3.4 also meets with Criterion A of Paragraph 81, as a check-off does not enhance the reliability of the BES. Requirement R3.4 should be retired as falling under Criterion B1 and Criterion A of Paragraph 81.

Requirement 6 in its entirety:

- Requirement R6.1 is redundant with COM-001, meeting Criterion B7 as redundant under Paragraph 81 and should be retired.
- Requirement R6.2 speaks to an action to be taken during capacity issues that is not feasible in accomplishing. Transaction arrangements are also a commercial practice and, thus, Requirement R6.2 meets Criterion B6 of Paragraph 81 and should be retired.

- Requirement R6.3 is redundant with EOP-001-2b Requirement R4 and Attachment 1, whereby meeting Criterion B7 as redundant under Paragraph 81 and should be retired.
- Requirement R6.4 does not provide for benefit for reliability of the BES, meeting Criterion A of Paragraph 81 and should be retired.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

   Please summarize your assessment:
   The 2009-03 Emergency Operations Five-Year Review Team (EOP FYRT) recommends that EOP-001-2.b and EOP-002-3.1 be revised and merged into a single standard identifying clearly and separately the Transmission Operator, Generation Operator and Reliability Coordinator issues as they relate to the BA and TOP (to address Paragraph 548 of Order 693) and how it needs to be planned and implemented for on the BES by the specific functional entities.
   - Requirement R1 needs clarity provided as to what an operating agreement constitutes, and adjust the VSL to reflect current interpretations with the number of agreements needed. Requirement R1 must also account for current interpretations found in the Appendix and other interpretations.
   - Requirement R2 needs clarity provided, as instructed by the Commission, on the ambiguity of the EOP standards as they relate to the responsibilities of the Transmission Operator and Balancing Authority.
   - Requirement R5, the need to share emergency plans with neighboring Transmission Operators and Balancing Authorities, should be removed as an administrative burden (identified in P81); however, the remaining language of the requirement should be affirmed.
   - Review is recommended for Attachment 1 as it relates to the GOP in light of recent BES events (Cold Weather Event).

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☒ Yes

☐ No

Please explain:
Appendix 1 attempts to define what a remote Balancing Authority is and should be addressed in future revisions of the Standard

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

   Additional measures must be provided with this standard. There are no performance measures. There are no VRFs with this standard. Requirement R1, once recommended clarity is provided as to what an operating agreement constitutes, adjustment to the VSL will be necessary to reflect current interpretations with the number of agreements needed.

☐ Yes

☒ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

☐ Yes

☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

☐ Yes

☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE – Requirement R1, R2, R5 and Attachment 1

☒ RETIRE – Requirements R3.1, R3.2, R3.4, R6.1, R6.2, R6.3, R6.4

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE – Requirements R1, R2, R5 and Attachment 1

☒ RETIRE – Requirements R3.1, R3.2, R3.4; Requirement R6 in its entirety; R6.1, R6.2, R6.3, R6.4

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Five-Year Review Template – EOP-002-3

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-002-3.1 Capacity and Energy Emergencies
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111,ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered “Yes” to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   - Requirement R1 is redundant with IRO-001 and PER-001-2 and should be retired under Criterion B7 of Paragraph 81.
   - Requirement R6 is redundant with BAL-002-1a and should be retired under Criterion B7 of Paragraph 81.
   - Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR, and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired. Due to the retirement of R9, LSE applicability should be removed in the standard.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

Please summarize your assessment:
The EOP FYRT recommends that EOP-001-2b and EOP-002-3.1 be revised and merged into a single standard to address redundancy in the stating that a plan should be implemented. Both standards are different enough that those requirements not identified in retirement recommendations under Paragraph 81 should be retained.

Requirement R8 and Attachment 1 have several issues regarding applicability to different functions and should be revised to eliminate discrepancies and for clarity. Attachment 1 needs to be reviewed for consistency with IRO and TOP standards. The EOP FYRT recommends review of the uniqueness as it relates to ERCOT and similarly situated BAs. The EOP FYRT recommends the future EOP SDT address the directive in Paragraph 573 of Order 693.

The EOP FYRT further recommends a language change in Requirement R2, replacing "interconnected system" with "Bulk Electric System." Requirements R3 and R4 need to be reviewed by the future EOP SDT to further define the word "emergency" (as Capacity Emergency, Emergency, and Energy Emergency are already NERC defined terms). The EOP FYRT recommends the following sentence in Requirement R5 to be struck: "Such unilateral adjustment may overload transmission facilities."

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes

☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

☒ Yes

☐ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or

consistency with other Reliability Standards? If you answered “Yes,” please describe the changes needed to achieve formatting and language consistency:

☐ Yes

☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered “Yes,” please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised: Requirement R9 (recommended for retirement under Paragraph 81) the TSP now has the ability to change the Transmission priority, which is in turn reflected in the IDC.

   ☒ Yes

   ☐ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE (and merge with EOP-001-2b)

☒ RETIRE – Requirements R1, R6 and R9 in its entirety.

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE (and merge with EOP-001-2b); Requirement R2, replacing "interconnected system" with "Bulk Electric System;" language revision in Requirement R2; Requirements R3 and R4 need to be reviewed by the future EOP SDT to further define the word "emergency" (as Capacity Emergency, Emergency, and Energy Emergency are already NERC defined terms); Requirement R5, strike "Such unilateral adjustment may overload transmission facilities."

☒ RETIRE – Requirements R1, R6, and R9 in its entirety. Due to the retirement of R9, LSE applicability should be removed in the standard.

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant

The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)

Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?

The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?

The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?

The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

> **Reliability Principles**
> NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.
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Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Five-Year Review Template – EOP-003-2

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-003-2 Load Shedding Plans
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111, ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   - Requirements R5 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R5 speaks to shedding loads in steps; that same process will be done in Requirement R1. Requirement R5 should be retired under Criterion B7 of Paragraph 81.
   - Requirements R6 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R6 speaks of two events that must be valid to tell the BA or TOP to shed more load, but overall the action of shedding load to meet insufficient generation is the same as stated in Requirement R1. Requirement R6 should be retired under Criterion B7 of Paragraph 81.
   - EOP-003-2– Recommend that Requirements R2, R4 and R7 be moved to PRC-010-0 or otherwise addressed during Project 2008-02 – Undervoltage Load Shedding.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

Please summarize your assessment:
The EOP FYRT team believes that Requirements R2, R4 and R7 should be coordinated with the revision of PRC-010 (Project 2008-02 Undervoltage Load Shedding) for inclusion in that standard. This is consistent with the review that was done for automatic underfrequency requirements and should also be performed for automatic undervoltage requirements.

Based on the recommendations received during the comment period, EOP FYRT further recommends R1 and R8 be considered to be combined. The EOP FYRT also received comments that EOP-003-2 should be combined with EOP-001-2.1b and EOP-002-3.1, and the EOP FYRT recommends this be evaluated in the SAR. In addition, the EOP FYRT recommends that the future EOP SDT evaluate the separation of the functional entity capabilities of the BA and the TOP responsibilities.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

   ☐ Yes

   ☒ No

   Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

   The Measures and Data retention should be reviewed and updated

   ☐ Yes

   ☒ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

   ☐ Yes

   ☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☐ Yes

   ☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE – Retire Requirements R5, R6, R2, R4 and R7 and address directives in Paragraphs 595 and 603 of Order 693

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*: See responses to questions 1, 2, and 4 above.

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE - Retire Requirements R5, R6, R2, R4 and R7 and address directives in Paragraphs 595 and 603 or Order 693; recommend for consideration Requirements R1 and R8 be combined; consider combining EOP-003-2 with EOP-001-2.1b and EOP-002-3.1; evaluate the separation of the functional entity capabilities of the BA and TOP responsibilities.

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)
The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative
The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?

The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?

The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles

NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Standards Announcement Reminder

Project 2009-03 Emergency Operations
EOP-011-1

Initial Ballot and Non-Binding Poll Now Open through August 15, 2014

Now Available

An initial ballot for **EOP-011-1 – Emergency Operations** and non-binding poll of the associated Violation Risk Factors (VRFs) and Violation Severity Levels (VSLs) are open through **8 p.m. Eastern on Friday, August 15, 2014.**

When reviewing EOP-011-1, stakeholders should also review Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS), as Requirements R2, R4, and R7 in EOP-003-2 – Load Shedding Plans are proposed to be replaced by Requirement R1 in the proposed PRC-010-1. Both projects and their Implementation Plans are being closely coordinated to ensure that there is no gap or duplication of requirements created by the work of the two teams.

Background information for this project can be found on the project page.

Instructions for Balloting

Members of the ballot pools associated with this project may log in and submit their vote for the standard and associated VRFs and VSLs by clicking here.

Next Steps

The ballot results will be announced and posted on the project page. The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Laura Anderson via email or by telephone at (404) 446-9671.

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Standards Announcement

Project 2009-03 Emergency Operations EOP-011-1

Formal Comment Period Now Open through August 15, 2014
Ballot Pools Forming Now through July 31, 2014

Now Available

A 45-day formal comment period for **EOP-011-1 – Emergency Operations** is open through **8 p.m. Eastern on Friday, August 15, 2014.**

When reviewing EOP-011-1, stakeholders should also review Project 2008-02 Undervoltage Load Shedding (UVLS) & Underfrequency Load Shedding (UFLS), as Requirements R2, R4, and R7 in EOP-003-2 – Load Shedding Plans are proposed to be replaced by Requirement R1 in the proposed PRC-010-1. Both projects and their implementation plans are being closely coordinated to ensure that there is no gap or duplication of requirements created by the work of the two teams.

If you have questions please contact Laura Anderson via email or by telephone at (404) 446-9671.

Background information for this project can be found on the project page.

Instructions for Commenting

Please use the electronic form to submit comments on the standard. If you experience any difficulties in using the electronic form, please contact Wendy Muller. An off-line, unofficial copy of the comment form is posted on the project page.

Instructions for Joining Ballot Pools

Ballot pools are currently being formed. Registered Ballot Body members must join the ballot pools to be eligible to cast ballots. Registered Ballot Body members may join the ballot pools at the following page: Join Ballot Pool.

During the pre-ballot window, members of the ballot pool may communicate with one another by using their "ballot pool list server." (Once the balloting begins, ballot pool members are prohibited from using the ballot pool list servers.) The list servers for this project are:

Ballot: bp-2009-03_EOP-011-1_STDS_in@nerc.com
Non-Binding Poll: bp-2009-03_EOP-011-1_nb@nerc.com

Next Steps
A ballot for the standard and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **August 6 through August 15, 2014.**

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

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Reliability Standard Audit Worksheet[1]

EOP-011-1 – Emergency Operations

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1													X		
R2	X														
R3									X						
R4									X						
R5									X						

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Transmission Operator shall develop, maintain and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan shall include the following elements:

1.1. Roles and responsibilities to activate the Emergency Operating Plan;

1.2. Strategies to prepare for and mitigate Emergencies including, at a minimum:

1.2.1. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing an operating Emergency;

1.2.2. Voltage control;

1.2.3. Cancellation or recall of Transmission and generation outages;

1.2.4. System reconfiguration;

1.2.5. Redispatch of generation request;

1.2.6. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding;

1.2.7. Mitigation of reliability impacts of extreme weather conditions; and

1.3. Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities.

M1. Each Transmission Operator will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R1 that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability Coordinator; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its plan was implemented in accordance with Requirement R1.

Registered Entity Response (Required):
Question: Has there ever been an Emergency where this Emergency Operating Plan has been implemented?
☐ Yes ☐ No
If yes, provide a list of such Emergencies.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
(R1) Provide documented plan.

(R1) Evidence of activation, such as operator logs, voice recordings, or other communications, for times when an Emergency has occurred.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R1

This section to be completed by the Compliance Enforcement Authority

	(R1) Confirm plan is dated and approved by the Reliability Coordinator.
	(R1) Confirm plan was developed in accordance with Requirement R1 Parts 1.1 through 1.3.
	(R1) Verify implementation of plan. (see note below)

Note to Auditor:

Requirement R1 includes activation of the Emergency Operating Plan. Part 1.2 Subparts of Requirement R1 include an extensive list of elements; therefore, if one or more of the elements are not applicable to the entity, it is acceptable to list the element(s) as Not Applicable in the entity's Emergency Operating Plan. Elements listed as Not Applicable should have corresponding verifiable rationale.

Auditors can gain reasonable assurance the plan was implemented by determining if specific actions prescribed by the plan have taken place. For example, if the plan calls for certain procedures to occur, then auditors could ask for evidence demonstrating the procedure has been implemented. As auditors should obtain reasonable, not absolute, assurance the plan was implemented, testing implementation on a sample basis may be appropriate.

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies. At a minimum, the Emergency Operating Plan shall include the following elements:

2.1. Roles and responsibilities to activate the Emergency Operating Plan;

2.2. Notification to the Reliability Coordinator, to include current and projected System conditions, when experiencing a Capacity Emergency or Energy Emergency;

2.3. Criteria to declare an Energy Emergency Alert, per Attachment 1;

2.4. Strategies to prepare for and mitigate Emergencies including, at a minimum:

2.4.1. Generating resources in its Balancing Authority Area:

2.4.1.1. capability and availability;

2.4.1.2. fuel supply and inventory concerns;

2.4.1.3. fuel switching capabilities; and

2.4.1.4. environmental constraints.

2.4.2. Voluntary Load reductions;

2.4.3. Public appeals;

2.4.4. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.4.5. Reduction of internal utility energy use;

2.4.6. Customer fuel switching;

2.4.7. Use of Interruptible Load, curtailable Load and demand response;

2.4.8. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; and

2.4.9. Mitigation of reliability impacts of extreme weather conditions.

2.5. Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators

M2. Each Balancing Authority will have a dated and approved Emergency Operating Plan developed in accordance with Requirement R2 that has been approved by its Reliability Coordinator, as shown with the documented approval from its Reliability Coordinator; and will have as evidence, such as operator logs or other operating documentation, voice recordings or, other communication documentation to show that its plan was implemented in accordance with Requirement R2.

Registered Entity Response (Required):

Question: Has there ever been an Emergency where this Emergency Operating Plan has been implemented?

☐ Yes ☐ No

If yes, provide a list of such Emergencies.

[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
(R2) Provide documented plan.
(R2) Evidence of activation, such as operator logs, voice recordings, or other communications, for times when an Emergency has occurred.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R2
This section to be completed by the Compliance Enforcement Authority

	(R2) Confirm plan is dated and approved by the Reliability Coordinator.
	(R2) Confirm plan was developed in accordance with Requirement R2 Parts 2.1 through 2.5.
	(R2) Verify implementation of plan. (see note below)

Note to Auditor:

Requirement R2 includes activation of the Emergency Operating Plan. Part 2.4 Subparts of Requirement R1 include an extensive list of elements; therefore, if one or more of the elements are not applicable to the entity, it is acceptable to list the element(s) as Not Applicable in the entity's Emergency Operating Plan. Elements listed as Not Applicable should have corresponding verifiable rationale.

Auditors can gain reasonable assurance the plan was implemented by determining if specific actions prescribed by the plan have taken place. For example, if the plan calls for certain procedures to occur, then auditors could ask for evidence demonstrating the procedure has been implemented. As auditors should obtain reasonable, not absolute, assurance the plan was implemented, testing implementation on a sample basis may be appropriate.

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. Each Reliability Coordinator shall approve or disapprove, with stated reasons for disapproval, Emergency Operating Plans submitted by Transmission Operators and Balancing Authorities within 30 calendar days of submittal.

M3. The Reliability Coordinator will have documentation, such as e-mails with receipts or registered mail receipts, that it approved or disapproved, with stated reasons for disapproval, the Transmission Operator and Balancing Authority submitted and revised Emergency Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
(R3) For Transmission Operators and Balancing Authorities, provide dated evidence of plan approval or disapproval. Evidence should include date of submission.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R3
This section to be completed by the Compliance Enforcement Authority

	(R3) Through the review of submitted documentation and interviews, confirm that the entity approves or disapproves plans within 30 calendar days.
	(R3) For disapproved plans, confirm the entity has stated reasons for disapproval.
Note to Auditor:	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as practical, other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators.

M4. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that will be used to determine if it communicated the Balancing Authority's or Transmission Operator's Emergency to impacted Reliability Coordinators, Balancing Authorities, and Transmission Operators in accordance with Requirement R4.

Registered Entity Response (Required):
Question: Has a Transmission Operator or Balancing Authority Emergency notification been received during the audit period?
☐ Yes ☐ No
If yes, provide a list of notifications. If no, then Requirement R4 is not applicable.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
(R4) Provide time-stamped evidence of entity's notification received from Balancing Authority or Transmission Operator of an Emergency, and time-stamped operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that demonstrate communication to other impacted Reliability Coordinators, Balancing Authorities, and Transmission Operators of an Emergency notification.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R4

This section to be completed by the Compliance Enforcement Authority

	(R4) Through the review of submitted documentation and interviews, confirm that other impacted Reliability Coordinators, Balancing Authorities, and Transmission Operators were informed of Emergencies as soon as practical.
Note to Auditor:	

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate an Energy Emergency Alert, as detailed in Attachment 1.

M5. Each Reliability Coordinator, that has had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that it initiated an Energy Emergency Alert, as detailed in Attachment 1 in accordance with Requirement R5.

Registered Entity Response (Required):
Question: Has a Balancing Authority experienced a potential or actual Energy Emergency in entity's Area during the audit period? ☐ Yes ☐ No
If yes, provide a list of such actual or potential Emergencies and proceed to Evidence Requested section below. If no, the Requirement R5 is not applicable.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
(R5) Provide a list of all potential or actual Energy Emergencies in entity's footprint and operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that demonstrate initiation of an Energy Emergency Alert.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R5

This section to be completed by the Compliance Enforcement Authority

	(R5) Through the review of submitted documentation and interviews, confirm that the entity properly initiates an Energy Emergency Alerts as detailed in Attachment 1.
Note to Auditor:	

Auditor Notes:

Additional Information:

Reliability Standard

The RSAW developer should provide the following information without hyperlinks. Update the information below as appropriate.
The full text of EOP-011-1 may be found on the NERC Web Site (www.nerc.com) under "Program Areas & Departments", "Reliability Standards."

In addition to the Reliability Standard, there is an applicable Implementation Plan available on the NERC Web Site.

In addition to the Reliability Standard, there is background information available on the NERC Web Site.

Capitalized terms in the Reliability Standard refer to terms in the NERC Glossary, which may be found on the NERC Web Site.

Sampling Methodology [If developer deems reference applicable]
Sampling is essential for auditing compliance with NERC Reliability Standards since it is not always possible or practical to test 100% of either the equipment, documentation, or both, associated with the full suite of enforceable standards. The Sampling Methodology Guidelines and Criteria (see NERC website), or sample guidelines, provided by the Electric Reliability Organization help to establish a minimum sample set for monitoring and enforcement uses in audits of NERC Reliability Standards.

Regulatory Language [Developer to ensure RSAW has been provided to NERC Legal for links to appropriate Regulatory Language – See example below]

E.g. FERC Order No. 742 paragraph 34: "Based on NERC's…….

E.g. FERC Order No. 742 Paragraph 55, Commission Determination: "We affirm NERC's…….

Selected Glossary Terms [If developer deems applicable]
The following Glossary terms are provided for convenience only. Please refer to the NERC web site for the current enforceable terms.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	7/17/2014	NERC Compliance, Standards, RSAWTF	New Document

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Standards Announcement

Project 2009-03 Emergency Operations
EOP-011-1

Initial Ballot and Non-Binding Poll Results

Now Available

An initial ballot for **EOP-011-1 – Emergency Operations** and a non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Friday, August 15, 2013**.

This standard achieved a quorum but did not receive sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot	Non-Binding Poll
Quorum /Approval	Quorum/Supportive Opinions
77.66% / 42.27%	77.37% / 42.23%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard. If the comments show the need for significant revisions, the standard will proceed to an additional comment and ballot period. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Wendy Muller,
Standards Development Administrator, or at 404-446-2560.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2009-03 Emergency Operations EOP-011-1
Ballot Period:	8/6/2014 - 8/15/2014
Ballot Type:	Initial
Total # Votes:	285
Total Ballot Pool:	367
Quorum:	**77.66 % The Quorum has been reached**
Weighted Segment Vote:	42.27 %
Ballot Results:	**The ballot has closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	**Ballot Pool**	**Segment Weight**	**# Votes**	**Fraction**	**# Votes**	**Fraction**	**Negative Vote without a Comment**	**Abstain**	**No Vote**
1 - Segment 1	100	1	33	0.5	33	0.5	0	6	28
2 - Segment 2	9	0.5	1	0.1	4	0.4	0	3	1
3 - Segment 3	84	1	21	0.339	41	0.661	1	8	13
4 - Segment 4	28	1	10	0.5	10	0.5	1	1	6
5 - Segment 5	78	1	23	0.469	26	0.531	0	5	24
6 - Segment 6	52	1	22	0.524	20	0.476	0	3	7
7 - Segment 7	2	0.2	2	0.2	0	0	0	0	0
8 - Segment 8	5	0.3	0	0	3	0.3	0	0	2
9 - Segment 9	2	0	0	0	0	0	0	1	1

10 - Segment 10	7	0.7	2	0.2	5	0.5	0	0	0
Totals	**367**	**6.7**	**114**	**2.832**	**142**	**3.868**	**2**	**27**	**82**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Negative	SUPPORTS THIRD PARTY COMMENTS - (Ameren)
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bob Bean)
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Negative	COMMENT RECEIVED
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax		
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.		
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Corporation	John Lindsey		
1	Colorado Springs Utilities	Shawna Speer		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy		
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO/ISO/RTO Council Standards Review Committee (SRC)) -

				(Supports PJM's Comments)
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil		
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson		
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	NB Power Corporation	Alan MacNaughton		
1	Nebraska Public Power District	Jamison Cawley		
1	New York Power Authority	Bruce Metruck		
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	

1	Peak Reliability	Jared Shakespeare	Negative	COMMENT RECEIVED
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Abstain	
1	PPL Electric Utilities Corp.	Brenda L Truhe		
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO/ISO/RTO Council Standards Review Committee (SRC)) - (Support PJM comments. (PJM Interconnection LLC))
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southern Indiana Gas and Electric Co.	Lynnae Wilson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tacoma Power	John Merrell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Marc Donaldson)
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Westar Energy	Allen Klassen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wind Energy Transmission Texas, LLC	Julius Horvath		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	

2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO Standards Review Committee)
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRC)
2	Southwest Power Pool, Inc.	Charles H. Yeung		
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Negative	COMMENT RECEIVED
3	APS	Sarah Kist	Negative	COMMENT RECEIVED
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Abstain	
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus		
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler		
3	City of Vineland	Kathy Caignon		
3	Cleco Corporation	Michelle A Corley		

3	Colorado Springs Utilities	Jean Mueller		
3	ComEd	John Bee	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Scanlon on behalf of Exelon)
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	COMMENT RECEIVED
3	Delmarva Power & Light Co.	Michael R. Mayer	Abstain	
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Negative	COMMENT RECEIVED
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO/ISO/RTO Council Standards Review Committee (SRC))
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC OC)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Georgia System Operations Corporation	Scott McGough	Negative	NO COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (See NSRF and ACES comments)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(AECI)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool (SPP) comments.)
3	New York Power Authority	David R Rivera		
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Orlando Utilities Commission	Ballard K Mutters		
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Abstain	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO/ISO/RTO Council Standards Review Committee (SRC)) - (PJM)
3	Puget Sound Energy, Inc.	Mariah R Kennedy		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Affirmative	
3	Tacoma Power	Marc Donaldson	Negative	COMMENT RECEIVED
				SUPPORTS THIRD

3	Tampa Electric Co.	Ronald L. Donahey	Negative	PARTY COMMENTS - (The FRCC Operating Committee (Member Services))
3	Tennessee Valley Authority	Ian S Grant	Negative	SUPPORTS THIRD PARTY COMMENTS - (TVA)
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Matt Beilfuss)
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY COMMENTS - (Russell Noble - Cowlitz PUD)
4	DTE Electric	Daniel Herring	Negative	COMMENT RECEIVED
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Carol Chinn	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	NO COMMENT RECEIVED
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey		
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy supports PJM's comments.)
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen		
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (SEC supports the comments of the FRCC

				Operating Committee submitted by John Libertz)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Marc Donaldson)
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (matt beilfuss,we energies)
5	Amerenue	Sam Dwyer		
5	American Electric Power	Thomas Foltz	Negative	COMMENT RECEIVED
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Previous comments submitted by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar		
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Negative	COMMENT RECEIVED
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Entergy Services, Inc.	Tracey Stubbs		
5	Exelon Nuclear	Mark F Draper	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Scanlon on behalf of Exelon)
5	First Wind	John Robertson		
				SUPPORTS THIRD PARTY COMMENTS - (NYISO/ISO/RTO

5	FirstEnergy Solutions	Kenneth Dresner	Negative	Council Standards Review Committee (SRC)) - (PJM)
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	Lakeland Electric	James M Howard	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Muncipal Power Agency)
5	Liberty Electric Power LLC	Daniel Duff	Abstain	
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Nevada Power Co.	Richard Salgo	Negative	COMMENT RECEIVED
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO/ISO/RTO Council Standards Review Committee (SRC)) - (PJM comments)
	Public Utility District No. 2 of Grant County,			

5	Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Adopt FRCC Operating Committee Comments)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Southern Indiana Gas and Electric Co.	Rob Collins		
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz - FRCC)
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Westar Energy	Bryan Taggart		
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Matt Beilfuss)
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
6	Ameren Missouri	Robert Quinlivan		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Standifur)
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Chris Scanlon on behalf of Exelon)
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)

6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO/ISO/RTO Council Standards Review Committee (SRC)) - (FirstEnergy supports PJM's comments)
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Reedy	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Abstain	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson		
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel		
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
6	PacifiCorp	Sandra L Shaffer	Negative	COMMENT RECEIVED
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NYISO/ISO/RTO Council Standards Review Committee (SRC)) - (PJM)
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee comments)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS -

				(Southern Company)
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Marc Donaldson)
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See the FRCC Operating Committee (Member Services) comments submitted by John A. Libertz)
6	Tennessee Valley Authority	Marjorie S. Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Comments)
6	Western Area Power Administration - UGP Marketing	Mark Messerli	Affirmative	
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Brickfield, Burchette, Ritts & Stone, P.C.	Thomas W Siegrist	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		David L Kiguel	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Foundation for Resilient Societies	William R Harris		
8	Massachusetts Attorney General	Frederick R Plett	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
9	New York State Public Service Commission	Diane J Barney	Abstain	
10	Florida Reliability Coordinating Council	Linda C Campbell	Negative	COMMENT RECEIVED
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED

Non-Binding Poll Results

Project 2009-03 Emergency Operations
EOP-011-1

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2009-03 Emergency Operations EOP-011-1 Non-Binding Poll
Poll Period:	8/06/2014 - 8/15/2014
Total # Opinions:	253
Total Ballot Pool:	327
Summaray Results:	77.37% of those who registered to participate provided an opinion or an abstention; 42.23% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole	Negative	SUPPORTS THIRD PARTY COMMENTS - (Bob Bean)
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Abstain	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
1	Black Hills Corp	Wes Wingen		
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Negative	COMMENT RECEIVED
1	Central Electric Power Cooperative	Michael B Bax		

1	Central Iowa Power Cooperative	Kevin J Lyons		
1	City of Tallahassee	Daniel S Langston	Negative	COMMENT RECEIVED
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Corporation	John Lindsey		
1	Colorado Springs Utilities	Shawna Speer		
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy		
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (Support PJM's Comments)
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton		
1	Florida Power & Light Co.	Mike O'Neil		
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)
1	Hydro One Networks, Inc.	Muhammed Ali	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane		
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson		
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Daniel Gibson	Affirmative	
1	Lakeland Electric	Larry E Watt		

1	Lincoln Electric System	Doug Bantam	Negative	SUPPORTS THIRD PARTY COMMENTS - (Lincoln Electric Comments)
1	Long Island Power Authority	Robert Ganley		
1	Los Angeles Department of Water & Power	faranak sarbaz		
1	Lower Colorado River Authority	Martyn Turner	Affirmative	
1	M & A Electric Power Cooperative	William Price		
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Negative	COMMENT RECEIVED
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	National Grid USA	Michael Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (National Grid supports NPCC's comments.)
1	Nebraska Public Power District	Jamison Cawley		
1	New York Power Authority	Bruce Metruck		
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Abstain	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz (American Electric Power))
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)

1	Omaha Public Power District	Doug Peterchuck	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO Comments)
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson	Affirmative	
1	Peak Reliability	Jared Shakespeare	Negative	COMMENT RECEIVED
1	Platte River Power Authority	John C. Collins	Abstain	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe		
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka	Affirmative	
1	SaskPower	Wayne Guttormson		
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee)
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Tacoma Power	John Merrell	Negative	SUPPORTS THIRD PARTY COMMENTS - (Marc Donaldson)
1	Tampa Electric Co.	Beth Young		

1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell	Affirmative	
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Affirmative	
1	U.S. Bureau of Reclamation	Richard T Jackson	Affirmative	
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wind Energy Transmission Texas, LLC	Julius Horvath		
1	Wolverine Power Supply Coop., Inc.	Michelle Clements		
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO Standards Review Committee)
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Negative	COMMENT RECEIVED
2	Independent Electricity System Operator	Leonard Kula	Negative	COMMENT RECEIVED
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC/SRC and NPCC/RSC)
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	SUPPORTS THIRD PARTY COMMENTS - (SRC)
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Negative	COMMENT RECEIVED

3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Avista Corp.	Scott J Kinney	Abstain	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Abstain	
3	City of Bartow, Florida	Matt Culverhouse	Negative	SUPPORTS THIRD PARTY COMMENTS - (Florida Municipal Power Agency)
3	City of Clewiston	Lynne Mila	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Homestead	Orestes J Garcia	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	City of Tallahassee	Bill R Fowler		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller		
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Negative	COMMENT RECEIVED
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Negative	COMMENT RECEIVED
3	FirstEnergy Corp.	Cindy E Stewart	Negative	COMMENT RECEIVED
3	Florida Keys Electric Cooperative	Tom B Anthony	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC OC)
3	Florida Municipal Power Agency	Joe McKinney	Negative	COMMENT RECEIVED

3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Gainesville Regional Utilities	Kenneth Simmons	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Georgia System Operations Corporation	Scott McGough	Negative	NO COMMENT RECEIVED
3	Great River Energy	Brian Glover	Negative	SUPPORTS THIRD PARTY COMMENTS - (See NSRF and ACES comments)
3	Hydro One Networks, Inc.	Ayesha Sabouba	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
3	JEA	Garry Baker	Negative	SUPPORTS THIRD PARTY COMMENTS - (JEA)
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (Associated Electric Cooperative, Inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Affirmative	
3	Kissimmee Utility Authority	Gregory D Woessner	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
3	Lakeland Electric	Mace D Hunter		
3	Lincoln Electric System	Jason Fortik	Negative	COMMENT RECEIVED
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (MidAmerican Energy Company)
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover		
3	National Grid USA	Brian E Shanahan	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC RSC)
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool (SPP) comments.)
3	New York Power Authority	David R Rivera		
3	Northern Indiana Public Service Co.	Ramon J Barany	Abstain	
3	NW Electric Power Cooperative, Inc.	David McDowell	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Ocala Utility Services	Randy Hahn	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC)
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Orlando Utilities Commission	Ballard K Mutters	Abstain	
3	Owensboro Municipal Utilities	Thomas T Lyons	Negative	SUPPORTS THIRD PARTY COMMENTS - (SERC OC)
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	
3	Puget Sound Energy, Inc.	Mariah R Kennedy		
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Affirmative	
3	Santee Cooper	James M Poston	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC

				Operating Committee)
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Negative	COMMENT RECEIVED
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant	Abstain	
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott		
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist		
4	City of Austin dba Austin Energy	Reza Ebrahimian	Abstain	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
4	City Utilities of Springfield, Missouri	John Allen	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Negative	SUPPORTS THIRD PARTY COMMENTS - (Russell Noble - Cowlitz PUD)
4	DTE Electric	Daniel Herring	Negative	COMMENT RECEIVED
4	Flathead Electric Cooperative	Russ Schneider	Affirmative	
4	Florida Municipal Power Agency	Carol Chinn	Negative	COMMENT RECEIVED
4	Georgia System Operations Corporation	Guy Andrews	Negative	NO COMMENT RECEIVED

4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey		
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy supports PJM's comments.)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Negative	SUPPORTS THIRD PARTY COMMENTS - (SEC supports the comments of the FRCC Operating Committee submitted by John Libertz)
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Negative	SUPPORTS THIRD PARTY COMMENTS - (Marc Donaldson)
4	Utility Services, Inc.	Brian Evans-Mongeon		
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Matt Beilfuss, We Energies)
5	Amerenue	Sam Dwyer		
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Negative	SUPPORTS THIRD PARTY COMMENTS - (Previous Comments submitted by AZPS)
5	Associated Electric Cooperative, Inc.	Matthew Pacobit		
5	Avista Corp.	Steve Wenke		
5	BC Hydro and Power Authority	Clement Ma	Abstain	

5	Black Hills Corp	George Tatar		
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Negative	SUPPORTS THIRD PARTY COMMENTS - (I agree with SCL comments)
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City of Austin dba Austin Energy	Jeanie Doty	Abstain	
5	City of Tallahassee	Karen Webb	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee (Member Services))
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex		
5	DTE Electric	Mark Stefaniak	Negative	COMMENT RECEIVED
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Entergy Services, Inc.	Tracey Stubbs		
5	First Wind	John Robertson		
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (PJM)
5	Florida Municipal Power Agency	David Schumann	Negative	COMMENT RECEIVED
5	Great River Energy	Preston L Walsh	Negative	SUPPORTS THIRD PARTY COMMENTS - (NSRF and ACES)

5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	JEA	John J Babik		
5	Kansas City Power & Light Co.	Brett Holland	Affirmative	
5	Kissimmee Utility Authority	Mike Blough	Negative	SUPPORTS THIRD PARTY COMMENTS - (FMPA)
5	Liberty Electric Power LLC	Daniel Duff	Abstain	
5	Lincoln Electric System	Dennis Florom	Negative	COMMENT RECEIVED
5	Los Angeles Department of Water & Power	Kenneth Silver		
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Nevada Power Co.	Richard Salgo	Abstain	
5	New York Power Authority	Wayne Sipperly	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Abstain	
5	Oglethorpe Power Corporation	Bernard Johnson		
5	Oklahoma Gas and Electric Co.	Henry L Staples		
5	Omaha Public Power District	Mahmood Z. Safi	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram		
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Abstain	

5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Affirmative	
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes		
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Negative	SUPPORTS THIRD PARTY COMMENTS - (Adopt FRCC Operating Committee Comments)
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson		
5	Tampa Electric Co.	RJames Rocha	Negative	SUPPORTS THIRD PARTY COMMENTS - (John A. Libertz - FRCC)
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot	Affirmative	
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox	Abstain	
6	Ameren Missouri	Robert Quinlivan		
6	APS	Randy A. Young	Negative	COMMENT RECEIVED
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Abstain	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	

6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy supports PJM's comments)
6	Florida Municipal Power Agency	Richard L. Montgomery	Negative	COMMENT RECEIVED
6	Florida Municipal Power Pool	Thomas Reedy	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC)
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer		
6	Lakeland Electric	Paul Shipps		
6	Lincoln Electric System	Eric Ruskamp	Negative	COMMENT RECEIVED
6	Los Angeles Department of Water & Power	Brad Packer		
6	Lower Colorado River Authority	Michael Shaw	Affirmative	
6	Luminant Energy	Brenda Hampton	Affirmative	
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC comments)
6	Northern Indiana Public Service Co.	Joseph O'Brien	Abstain	
6	Oglethorpe Power Corporation	Donna Johnson		
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel		
6	Omaha Public Power District	Douglas Collins	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine	Abstain	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)

6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Affirmative	
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Negative	SUPPORTS THIRD PARTY COMMENTS - (FRCC Operating Committee comments)
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard	Affirmative	
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Marc Donaldson)
6	Tampa Electric Co.	Benjamin F Smith II	Negative	SUPPORTS THIRD PARTY COMMENTS - (See the FRCC Operating Committee (Member Services) comments submitted by John A. Libertz)
6	Tennessee Valley Authority	Marjorie S. Parsons	Abstain	
7	Brickfield, Burchette, Ritts & Stone, P.C.	Thomas W Siegrist	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake	Affirmative	
8		Roger C Zaklukiewicz	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8		David L Kiguel	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
8	Foundation for Resilient Societies	William R Harris		
8	Massachusetts Attorney General	Frederick R Plett	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (NPCC)
8	Volkmann Consulting, Inc.	Terry Volkmann		
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson		
10	Florida Reliability Coordinating Council	Linda C Campbell	Negative	COMMENT RECEIVED
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC)
10	Northeast Power Coordinating Council	Guy V. Zito	Negative	COMMENT RECEIVED
10	ReliabilityFirst	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED

Individual or group. (56 Responses)
Name (32 Responses)
Organization (32 Responses)
Group Name (24 Responses)
Lead Contact (24 Responses)
Contact Organization (24 Responses)
Question 1 (37 Responses)
Question 1 Comments (45 Responses)
Question 2 (40 Responses)
Question 2 Comments (45 Responses)
Question 3 (43 Responses)
Question 3 Comments (45 Responses)
Question 4 (41 Responses)
Question 4 Comments (45 Responses)
Question 5 (32 Responses)
Question 5 Comments (45 Responses)
Question 6 (31 Responses)
Question 6 Comments (45 Responses)
Question 7 (0 Responses)
Question 7 Comments (45 Responses)

Individual
Wendy
NERC
Group
Northeast Power Coordinating Council
Guy Zito
Northeast Power Coordinating Council
Yes
For consistency with the Rationale listed for R2 pertaining to “If any Parts of Requirement R2 are not applicable”, a similar statement should be listed under the Rationale for R1. Suggest adding the wording: “If any Parts of Requirement R1, Part 1.2 are not applicable, the Transmission Operator should note 'not applicable' in their plan.”
Yes
We agree that Emergency Operating Plans should be coordinated.
Yes
We are concerned with the RC obligation to simply approve the TOP/BA EOPs. It implies that approval could be checking compliance. The Requirement or the Technical Guidance should provide direction and meaning to the approval. If the SDT was to codify the requirement then we would like to suggest language consistent with EOP-006. Suggest: R3. Each Reliability Coordinator shall review the Emergency Operating Plans (EOPs) of the Transmission Operators and Balancing Authority within its Reliability Coordinator Area. 3.1 The Reliability Coordinator shall determine whether the Transmission Operator’s or Balancing Authority’s EOP is coordinated and compatible with the Reliability Coordinator’s EOP and other Transmission Operators’ EOPs within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with reasons stated, the Transmission Operator’s or Balancing Authority’s submitted EOP within 30 calendar days following the receipt of the EOP from the Transmission Operator or Balancing Authority. As an alternative, a section in the Guidelines and Technical Basis could be written to provide guidance. The RC role in the TOP or BA process to develop an EOP can vary based on the quantity of Emergency Operating Plans being submitted. When an RC provides its approval of a submitted EOP the RC must review the submitted EOP to verify it is compatible and coordinated with the RC’s overarching emergency operating plans developed for its Wide Area responsibility.
Yes

No
The proposed move of utilizing Operating Reserve (OR) from EEA 2 to EEA 3 does not present any problems. However, we are concerned with the added sentence that “In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement.” The sentence needs to be clarified. Even though the statement doesn’t stipulate that load has to be shed, having to shed load can be construed. We do not agree that the deficient BA needs to shed firm load to meet the Operating Reserve requirement. Operating Reserve is carried to guard against demand variations and contingencies resulting from a loss of generating resource or import, and system contingencies. A BA should only shed load if a contingency occurs necessitating load reduction to restore system operation within well-defined limits. You do not operate to shed firm load to avoid having to shed firm load. The conclusion that may be reached is that a BA is required to shed firm load prior to committing its remaining Operating Reserves. This can be clarified by rephrasing to: In this situation, the requesting BA must be able to have an amount of firm Load shed if necessary to supplement its remaining Operating Reserves in order to meet its Operating Reserve requirement.”
No
The Time Horizon for R1, R2 and R3 is currently Operations Planning. This should be Long-Term Planning. The definition of the two horizons are; Long-term Planning — a planning horizon of one year or longer. And Operations Planning — operating and resource plans from day-ahead up to and including seasonal. The EOP is developed for a period greater than a season. The condition “did not do so as soon as practical” in the HIGH VSL for R4 cannot be determined with any certainty or supported evidence. R4 itself need to be revised to provide the measurability to support compliance assessment. Please see the comment under Q7 regarding R4. We suggest revising the Medium VSL for R5 to Lower since failure to notify others that the alert has ended does not result in any unreliable operations.
The Drafting Team should revise the Evidence Retention section of this standard which is very specific requiring the retention of all versions of the EOP within the audit period. This is inconsistent with the allowed practice of maintaining detailed revision history within the current version. With the possible use of RAI to extend audit cycles (which could increase the time between TOP audits to more than 3 years), TOP and BA’s will be maintaining versions of EOP solely for backward horizon compliance monitoring. A more effective approach is to require the TOP and BA to retain the current version with revision history and utilize spot checking to monitor compliance. The wholesale replacement of “Energy Deficient Entity” with “Requesting BA” results in some inconsistency with Condition (1) in the General Responsibility A.1 of Attachment 1, which indicates that a RC may initiate an EEA on its own request. Clearly, a RC will likely issue an EEA when it identifies a BA(s) in its RC Area is anticipating or experiencing energy deficiency. Nonetheless, the use of “Requesting BA” only in the rest of Attachment 1 fails to address the cases where a BA is energy deficient but it does not request its RC to initiate an EEA; rather, it is the RC that initiates the EEA before being requested. We suggest the SDT to consider replacing “Requesting BA” with “Energy Deficient BA” or simply reinstate the phrase “Energy Deficient Entity”. EOP-011-1 Parts 1.2 and 2.4 should retain the phrase to ‘include the applicable elements’ below, and remove the phrase ‘at a minimum’. This would be consistent with the previous language contained in existing EOP-001 R4 and allow for solutions that do not exist or are not ‘applicable’ in certain areas. Is “impact” a measurable word that should be in the standard? In sub-Part 1.2 and Part 2.5 the TOP and BA are required to coordinate with impacted TOP and impacted BA. Impacted could mean electrically affected by the EOP or it could mean having a role to play in executing the EOP. In R4 the ambiguity in impact is similar. Guidance or clarity is needed around this term. R2 – For consistency with Part 1.1 remove ‘and implement’ from Part 2.1 (this is not struck on the redlined version, but it does show that it has been removed on the clean version). R2 – For consistency with R1; the content of Parts 2.2 and 2.3 should be moved as sub-Parts below Part 2.4 instead of included as standalone Parts 2.2 and 2.3. R2- The requirement appears to use a newly capitalized term “Capacity”. This term is not included in the NERC Glossary of Terms currently posted. If the intent is to use the existing defined terms, Capacity Emergency and Energy Emergency, then the SDT needs to write the requirement accordingly. Regarding requirement R4, first, requirement R4 is not measurable since there is no clear yardstick for “as soon as practical”. This concept was a challenge in the development of FAC-003-3. In FAC-003-3 the phrase “without any intentional time delay” was used, or consider adding

language similar to TOP-001-2 requirement R5 that uses the phrase “unless conditions do not permit such communications.” Secondly, the Drafting Team should consider removing EOP-011 R4 since it is redundant to the following requirements: - IRO-015-1 R1 requires RC’s to communicate notifications that impact neighboring RC’s - EOP-002-4 R2 requires BA’s to communicate notifications that impact neighboring BA’s - TOP-001-2 R5 requires TOP’s to communicate notifications that impact neighboring TOP’s Finally, the draft IRO-014 R3 may introduce double jeopardy for non-compliance. The SDT should coordinate with the Project 2014-03 Revisions to TOP and IRO Standards Drafting Team IRO-014-3 requirement R3 and EOP-011-1 requirement R4. Those two requirements are very similar. It could argued that receiving a notification of an Emergency results in the RC identifying an actual emergency and then both EOP-011-1 and IRO-14-3 require the RC to notify other RC’s. EOP-011-1 then goes further and requires the RC to notify other TOPs and BAs. The notification to other RCs is covered by these two Standards. This double jeopardy needs to be addressed.
Individual
Julius Horvath
Wind Energy Transmission Texas, LLC
Yes
Yes
No
The proposed EOP change only further places unnecessary burden on the RC. We cannot understand why the RC should need to approve a company specific emergency plan. We have no issues with coordinating our EOP with the RC and neighboring TOPs, but we do not agree with requiring RC approval of company specific EOPs.
Yes
Yes
No
The VSLs specifically state "The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan" and we don't agree with requiring the RC to approve company specific EOPs, therefore we cannot support the VSLs as written either.
Group
The FRCC Operating Committee (Member Services)
John A. Libertz
FRCC
Yes
Yes
No
We do not feel that the approach by the SDT is fully responsive to the FERC directive nor is it consistent with the desire expressed in the order. In addition there is lack of clarity on what criteria the RCs should use to approve or disapprove individual TOP and BA plans. The requirement as written appears to simply add administrative burden and compliance implications that add little to improving reliability. Adding an “auditing” purpose to RCs duplicates compliance monitoring oversight of TOP and BA entities inappropriately and should not be added to the responsibility of RCs. We do acknowledge that the RC role is important in coordinating response to Emergencies however, contrary to EOP-006 (restoration) where the RC has a central role in guiding System restoration, individual BA and TOP responses to emergencies within their area is a much different operating scenario and the RCs role are likely to be very different. If the SDT determines that it is essential to have the RC involved in the approval process, we request criteria be provided for

consistency otherwise criteria could be created by individual RCs and inconsistently applied across interconnections.
Yes
Yes
R1 and R2 should not have “Reliability Coordinator-approved” included in the requirement. (Please see comments associated with Question 3.) R1.2.6 and R2.4.8. We agree with the rationale but would like additional language added to the standard to clarify the intent. Adding a “(UFLS and UVLS as applicable)” after automatic Load Shedding would be beneficial since the rationale box will not be included in the standard. Creating a new defined term would be preferred over the combining of two separate defined terms (as noted in the Rationale for Requirement 1). It will add confusion to future readers when combined terms are used without specifically noting the combining of those terms.
Group
Arizona Public Service Company
Janet Smith
Arizona Public Service Company
Yes
No
AZPS supported the inclusion of Requirement 3 in the standard. The role of the Reliability Coordinator is one of oversight and coordination. They have the wide-area viewpoint necessary to assess emergency operations plans in aggregate and see the interdependencies of the plans. AZPS recognizes that this updated proposal still has the RC included in an approver role but contends that the coordination piece is of equal importance. The standard now simply requires RC approval. There is no implication in the language that the RC should be reviewing all plans in aggregate looking for the regional impact of the combined plans. AZPS suggests that the RC is appropriate entity to both coordinate and approve the plans.
Yes
Yes
No
This appears to constitute a change in the emergency response ideology. Under the current standard, it is not necessary to shed load to restore reserves at an EEA 2, unless they are called upon. The new proposal states that an entity must have the ability to shed load to restore reserves. The SDT has provided no rationale for this change. AZPS requests clarification on the rationale for this change if in fact the standard now states that firm customer load should be shed to restore reserves. As a secondary issue the movement of operating reserves from EEA 2 to EEA 3 is that it reduces the clarity of the EEA levels. The attachment to EOP-002-3.1 provides a clear trigger for each EEA level. Level 1 is triggered by having all resources in use while still maintaining the ability to meet all operating requirements. Level 2 is triggered by becoming reserve deficient while still maintaining the ability to meet all of your firm commitments. Level 3 is triggered by losing the ability to meet all of your firm commitments thereby becoming ACE deficient. The proposed changes leave the Level 1 trigger intact. The previous Level 2 trigger becomes the trigger for Level 3. This leaves no definitive trigger for Level 2. AZPS believes this will cause confusion as TOPs transition between the EEA levels. Therefore AZPS recommends that the Operating Reserves remain in EEA 2 as in EOP-002-3.1.
Yes
Individual

Len Kula
Independent Electricity System Operator
Yes
Yes
Yes
Yes
No
We are indifferent with the proposed move of utilizing Operating Reserve (OR) from EEA 2 to EEA 3. However, we wonder if the result will be a greater # of EEA3 events. Also we are concerned with the added sentence that “In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement.” We do not agree that the deficient BA needs to shed firm load to meet the OR requirement since OR is carried to guard against demand variations and contingencies resulting in loss of generating resource or import. For so long as OR is still available, albeit depleted, a BA should be able to continue to utilize its OR to meet resource/demand/interchange balance. A BA should only shed load if a contingency occurs or when the OR is fully utilized and there still remains a resource/demand/interchange imbalance. In short, we do not support the idea of shedding firm load to avoid having to shed firm load when a resource contingency occurs or before the OR is fully utilized, unless such post-contingency actions are not quick enough to prevent instability or cascading due to loss of resource/import contingencies. Therefore, we suggest revising the last sentence in Section 3.2 of Attachment 1 to: “In this situation, the requesting BA must be able to shed firm Load if it is unable to meet resource/demand/interchange balance after fully utilizing its Operating Reserve.
No
1. The condition “did not do so as soon as practical” in the HIGH VSL for R4 cannot be determined with any certainty or supported evidence. R4 itself need to be revised to provide the measurability to support compliance assessment. Please see our comment under Q7. 2. We suggest moving the Medium VSL for R5 to Lower since failure to notify others that the alert has ended does not result in any unreliable operations
1. Requirement R4 is not measurable since there is no clear yardstick for “as soon as practical”. While a time period may be subject to different views, we nevertheless suggest the SDT consider revising it to “shall notify, as soon as practical but no later than 5 minutes after receiving the notification,” to put a bound on the time frame to support compliance assessment. 2. The wholesale replacement of “Energy Deficient Entity” with “Requesting BA” results in some inconsistency with Condition (1) in the General Responsibility A.1 of Attachment 1, which indicates that a RC may initiated an EEA on its own request. Clearly, a RC will likely issue an EEA when it identifies a BA(s) in its RC Area is anticipating or experiencing energy deficiency. Nonetheless, the use of “Requesting BA” only in the rest of Attachment 1 fails to address the cases where a BA is energy deficient but it does not request its RC to initiate an EEA; rather, it’s the RC that initiates the EEA before being requested. We suggest the SDT to consider replacing “Requesting BA” with “Energy Deficient BA” or simply reinstate the phrase “Energy Deficient Entity”.
Individual
Thomas Foltz
American Electric Power
No
AEP has no objection to the qualifier “Operator-controlled”, however each unique situation would dictate whether the appropriate action to take would be manual or automatic. R1 should allow such flexibility in the strategies specified.
No
AEP disagrees with the change, and recommends that this requirement return to the approach proposed in the previous draft. AEP believes the Reliability Coordinator is in the best position to take

the lead in coordinating its Balancing Authority and Transmission Operator plans. This form of coordination could involve the Reliability Coordinator reviewing the plans to ensure that the plans are compatible with the RC overarching plan (FERC Order No 693 Paragraph 548 hints at the Reliability Coordinator having an "overarching plan.") and support reliability of the Bulk Electric System. FERC Order No 693, Paragraph 547 states in part "While balancing authorities and transmission operators are capable of developing, maintaining and implementing plans to mitigate operating emergencies for their specific areas of responsibility, unlike reliability coordinators, they do not have wide-area views." We are in favor of the Reliability Coordinator hosting workshops as a platform to allow its local Balancing Authority and Transmission Operator to air the plans as another form of coordination (MISO presently hosts workshops to accomplish this coordination task for its members.).
No
AEP does not support the Reliability Coordinator formally approving the Balancing Authority and Transmission Operator Emergency Plans. In FERC Order No. 693, Paragraph 632 (EOP-006-1), FERC clearly requires the Reliability Coordinator to be involved in the development and approval of restoration plans. FERC did not make this distinction of the Reliability Coordinator approving the EOP (EOP-001-0) plans. We believe EOP-011-1 R3 violates the intent of Paragraph 81 criteria B1. AEP supports the Reliability Coordinator role as a coordinator of the Operator plans as noted in our response to question #2.
Yes
AEP agrees, and appreciates the drafting team's willingness to accept our earlier recommendation that R5 be removed.
The drafting team's consideration of comments document states the following: "The EOP SDT discussed the many suggestions received for Requirement R1 and its detailed requirement parts. Based on comments received, the EOP SDT added details into the Requirement R1 Rationale that if any Requirement R1 Parts are not applicable, that the Transmission Operator should note "not applicable" in their plan." We find no mention of this in the R1 callout, though similar language is included in the callout for R2. Regardless, while we agree with such an allowance, we believe it should be included in the standard itself. Otherwise, an auditor could strictly adhere to the standard where it states "shall include the following elements."
Individual
Anthony Jablonski
ReliabilityFirst
Yes
No
1. Requirement R1 and R2 a. The following comment was supplied during the previous comment period and ReliabilityFirst believes it was not addressed. ReliabilityFirst requests the following comment be responded to: ReliabilityFirst believes the "implement a Reliability Coordinator-approved Emergency Operating Plan" language is troublesome in a scenario where a Reliability Coordinator disapproves the Emergency Operating Plan (per Requirement R4). In this scenario, the Transmission Operator/Balancing Authority could be compliant with developing and maintaining the plan but without Reliability Coordinator approval of the plan, the Transmission Operator/Balancing Authority could potentially be deemed non-compliant with Requirement R1 and R2. ReliabilityFirst believes the "implement a Reliability Coordinator-approved Emergency Operating Plan" language should be taken out of Requirements R1 and R2 respectively. ReliabilityFirst recommends including a new Requirement R5 which states "Upon Reliability Coordinator approval of the Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans, the Transmission Operator and Balancing Authority shall implement the approved Emergency Operating Plan."
Yes

No
1. VSL for Requirement R1 - The second “OR” under the High VSL should not include the words “failed” in the first sentence fragment. ReliabilityFirst recommends the following for consideration: “The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but…” 2. VSL for Requirement R5 - The VSLs for R5 all reference items in attachment 1 and not the actual requirement. RF recommends there be one Severe VSL which states: “The Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency Alert, as detailed in Attachment 1.”
ReliabilityFirst submits the following comments for consideration: 1. Requirement R4 - ReliabilityFirst believes the term “as soon as practical” is ambiguous, does not provide any added value, and should not be used in standards. This term leaves the requirement open to interpretation and potential problems in compliance monitoring and enforcement. ReliabilityFirst recommends the following for consideration “Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify the impacted Reliability Coordinators, Balancing Authorities and Transmission Operators[, within 30 minutes of the start of the Emergency.]” This time frame of 30 minutes is used throughout similar standards and we believe it is applicable here as well. 2. Requirement R7 - ReliabilityFirst believes the term “as soon as practical is ambiguous, does not provide any added value, and should not be used in standards. This term leaves the requirement open to interpretation and potential problems in compliance monitoring and enforcement. ReliabilityFirst recommends the following for consideration “Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify the impacted Reliability Coordinators, Balancing Authorities and Transmission Operators[, within 30 minutes of the start of the Emergency.]” This time frame of 30 minutes is used throughout similar standards and we believe it is applicable here as well 3. Requirement R9 - ReliabilityFirst believes there should a timeframe associated with how long a Reliability Coordinator has to initiate a NERC Energy Emergency Alert following a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency. ReliabilityFirst recommends the following for consideration: “Each Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate a NERC Energy Emergency Alert, as detailed in Attachment 1[, within 30 minutes of request.]” This time frame of 30 minutes is used throughout similar standards and we believe it is applicable here as well
Individual
John Brockhan
CenterPoint Energy Houston Electric, LLC
Yes
No
Please see CenterPoint Energy response to Question 3. CenterPoint Energy believes the coordination of the Emergency Operating Plans of the TOPs and BAs within an RC area should be administered by the RC, similar to the approach taken by the FERC-approved EOP-010-1 GMD standard’s R1.2.
No
Since FERC did not mandate RC approval in Paragraph 548, CenterPoint Energy does not believe that using RC approval is the most sensible method to satisfy FERC’s directive. Instead, CenterPoint Energy recommends that EOP-011-1 adopts an approach similar to the FERC-approved EOP-010-1 GMD standard. Thus, for R1: “Each RC shall develop, maintain, and implement an Emergency Operating Plan that coordinates Emergency Operating Procedures or Emergency Operating Processes within its RC Area. The Emergency Operating Plan shall include a process for the RC to review and to coordinate the Emergency Operating Procedures or Emergency Operating Processes of the TOPs and BAs within its RC Area.” For R2: “Each TOP shall develop, maintain, and implement Emergency Operating Procedures or Emergency Operating Processes to mitigate operating Emergencies on its Transmission system. At a minimum, the Operating Procedures or Operating Processes shall include the following elements:…”. For R3: “Each BA shall develop, maintain, and implement Emergency

Operating Procedures or Emergency Operating Processes to mitigate Capacity and Energy Emergencies. At a minimum, the Operating Procedures or Operating Processes shall include the following elements:...”.
No
CenterPoint Energy agrees with the SDT that EOP-011-1 draft 1’s R5 is redundant with currently-enforceable TOP-001-1a and therefore should be removed. However, CenterPoint Energy disagrees with the SDT’s subsequent decision to re-create the same redundant requirement as EOP-011-1 draft 2 R1.2.1. Therefore, draft 2’s R1.2.1 should be deleted because of the SDT’s stated redundancy.
No
CenterPoint Energy does not disagree with the change regarding “Operating Reserves”. However, CenterPoint Energy suggests the following revisions be made to Attachment 1-EOP-011-1 (Energy Emergency Alerts): Under Section B, EEA Levels, the Introduction paragraph speaks to establishing four levels of EEAs. CenterPoint Energy suggests changing this language to establishing three (3) levels of EEAs since there are only three levels used and described under Section B. Additionally, under Section B, 3. EEA 3, CenterPoint Energy does not feel that language in 3.5 (Returning to pre-Emergency conditions) should be included in the description for EEA 3. CenterPoint Energy suggests removing 3.5 and Alert 0 - Termination from the description of EEA 3 and adding a Section C which would include language described in 3.5 (Returning to pre-Emergency conditions) as well as Alert 0 – Termination. Furthermore, CenterPoint Energy suggest changing Alert 0 – Termination to just Termination.
No
For R1 and R2, all the listed violation scenarios are documentation issues, except for the 3rd scenario of the Severe VSL for these two requirements. CenterPoint Energy firmly believes there should be no High or Severe VSL for simply failing to document a process or procedure. High or Severe VSL’s should only apply to egregious violations that had a tangible impact on the reliability of the BES. Thus, CenterPoint Energy recommends that R1 and R2’s VSL’s be revised to focus more on performance-based issues with the following language. Lower VSL: The Transmission Operator does not have documented Emergency Operating Procedures or Emergency Operating Processes to mitigate operating Emergencies on its Transmission System; or the Transmission Operator has documented Emergency Operating Procedures or Emergency Operating Processes to mitigate operating Emergencies on its Transmission System but failed to coordinate with its Reliability Coordinator Emergency Operating Plan; or the Transmission Operator had documented Emergency Operating Procedures or Emergency Operating Processes to mitigate operating Emergencies on its Transmission System that were coordinated with its a Reliability Coordinator Emergency Operating but failed to include one or more of the sub-parts of R1 as applicable. Moderate VSL: The Transmission Operator had documented Emergency Operating Procedures or Emergency Operating Processes to mitigate operating Emergencies on its Transmission System that were coordinated with its Reliability Coordinator Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to implement one of the applicable sub-parts of R1 for an operating Emergency. High VSL: ...but failed to implement two of the applicable sub-parts of R1 for an operating Emergency. Severe VSL: ...but failed to implement three or more of the applicable sub-parts of R1 for an operating Emergency.
CenterPoint Energy appreciates the efforts and the commitment of the SDT and the opportunity to provide the following additional comments: 1) CenterPoint Energy recommends that the phrase “for times when an Emergency has occurred” be added to M1 and M2 of EOP-011-1 draft 2, when referencing operator logs and voice recordings. This is to mirror EOP-011-1’s draft RSAW, where under the “Evidence Requested” section of R1 and R2, the guidance states “Evidence of activation, such as operator logs, voice recordings, or other communications, for times when an Emergency has occurred.” 2) If the SDT retains the RC-approval approach, CenterPoint Energy is concerned that the language in Requirement R1 restricts TOPs to one single Emergency Operating Plan. CenterPoint Energy believes that TOPs should be able to utilize multiple plans to address R1, as long as the plans in aggregate include all the required elements. Thus, R1 should be revised to state: “Each TOP shall develop, maintain, and implement one or more Reliability Coordinator-approved Emergency Operating Plan(s) to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan(s), in aggregate, shall include the following elements:”. 3) CenterPoint Energy believes R1 Part 1.1 is unnecessary. TOP-001-1a Requirement R1 states that TOPs have the

responsibility and clear decision-making authority to take whatever actions necessary to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies. TOP 001-1a R2 also states that, “Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment, shedding firm load, etc.” Further declaration of roles and responsibilities are unnecessary. CenterPoint Energy recommends R1 Part 1.1 be deleted. 4) CenterPoint Energy believes R1 Part 1.2.2 is duplicative of various existing requirements. TOP-004-2 R6 already requires TOPs to have policies and procedures that address monitoring and controlling of voltage levels that impact reliability. Additionally, VAR-001-3 R1 and R2 require TOPs to have sufficient reactive resources for Contingency conditions and to have formal policies and procedures for monitoring and controlling voltage levels “under normal and contingency conditions”. Furthermore, voltage control as proposed in the draft standard is not part of the currently effective EOP-001 Attachment 1, and so does need to be addressd within EOP-011. CenterPoint Energy believes Part 1.2.2 is unnecessary and should be deleted from EOP-011-1. 5) CenterPoint Energy believes the “extreme weather conditions” referenced in R1 Part 1.2.7 is vague, and it would be challenging for TOPs and auditors to interpret what qualifies as “extreme”. CenterPoint Energy believes that not all events of “extreme” weather result in emergency conditions requiring special mitigation strategies. In addition the Company believes that various existing operational planning requirements are sufficient to cover preparedness for extreme weather, such as TOP-005-2a R2 and Attachment 1 and TOP-006-2 R4. Therefore, Part 1.2.7 is unnecessary and should be deleted. If, however, an “extreme weather conditions” requirement must be retained, CenterPoint Energy recommends Part 1.2.7 be revised to state: “Mitigation of reliability impacts of extreme weather conditions defined by the Transmission Operator.” 6) CenterPoint Energy requests the SDT review the combined term “Transmission System”. CenterPoint Energy believes the definition of transmission system is well understood; however, using the capitalized term “System” (a combination of generation, transmission, and distribution components.)introduces a conflict with the meaning of the defined term “Transmission”. CenterPoint Energy recommends using the lower case term “system” in this instance.
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Individual
Michael Haff
Seminole Electric Cooperative, Inc.
Group
Colorado Springs Utilities
Kaleb Brimhall
Colorado Springs Utilities
Yes
We think that “Operator-Controlled” is redundant as “manual load shedding” requires that it is initiated and operated by someone. We do not object, but think it unnecessary.
Yes
Yes
Yes
Yes
No
1) R1 VSLs – How come the RC is approving a EOP that does not contain the required information? 2) R1 VSLs – High VSL 2nd condition. If we fail to have a plan then we definitely failed to include 1.1 and 1.3. Think there is a typo. 3) R3 VSLs – The RC should be responsible for verifying that EOPs

have all the necessary parts before approval. This needs to be included in the VSLs for the RC under R3.
Individual
Linda Campbell
FRCC
There is a potential for confusion due the SDTs use of the terms “Emergency Operation Plan”. It appears that the SDTs intent is for readers to utilize the definitions in the Glossary of Terms for “Emergency” and “Operating Plan” to determine what is required by the Standard. The combining of these two definitions is confusing. If the SDT decides that the continued use of “Emergency Operation Plan” is needed, then a new definition should be developed to provide clarity around the intent and content of the plan. Therefore, the potential confusion of what an “Emergency Operating Plan” actually entails could create difficulties when assessing compliance and is directly related to the ‘measures’ and the ‘enforceability’ of the requirements. The use of the term ‘implement’ in requirements R1 and R2 is confusing when compared to the language in Measures M1 and M2 and the RSAW. What does ‘implement’ actually mean in the context of the requirements? The requirements (R1 and R2) require an Emergency Operating Plan to be developed, maintained and implemented. Does this mean that the plan will be developed to include the required attributes identified in the requirement sub-bullets, will be maintained with periodic reviews to ensure the plan will appropriately address the specific emergency condition and be implemented. I believe implemented means that the plan is available for the System Operator’s use, training has been completed and the Operators are proficient in the application of the plan. But when you read the Measure and the RSAW they are looking for evidence that the plan was actually activated in response to an emergency which is not part of R1 and R2. So if the plan is never used by the operator is that part of the audit over? R3 requires approval of the plan from the RC, but there is not documented criteria for the RC to assess approval and therefore is very difficult to assess compliance. Unless this is simply an exercise in documenting a ‘yes’ or ‘no’
Individual
Amy Casuscelli
Xcel Energy
Yes
Yes
Yes
Yes
Yes
In section 3.2 of the Attachment 1, we believe the revised wording below provides additional clarity: 3.2 Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. In this situation, the requesting BA must be [prepared] to shed an amount of firm Load in order to meet its Operating Reserve requirement.

Individual
Russell Noble
Public Utility District No. 1 of Cowlitz County, WA
Yes
However, PUD No. 1 of Cowlitz County, WA (District) finds the following sentence in the Rationale for R1 to be awkward: "It is the EOP SDT's intent for Requirement R1 Part 1.2.6 that what is unwanted is the use manual Load shedding which is already armed for automatic Load shedding." The District also finds the following phrase in the Rationale for R2 "…is to minimize as much as possible the use manual Load shedding…" is missing the word "of" between "use" and "manual," or might be improved with the words "the use" being replaced with "using." The District suggests using similar construct for both rationales, with a preference with the verbiage used for Requirement R2.
No
The District believes the SDT intent is to advance a results based requirement for each BA and TOP to make a good faith effort to coordinate the Emergency Operating Plans (Plans), both during development and their implementation. The District agrees with this; however, Requirement Parts 1.3 & 2.5 will not assure the Plans will be coordinated among mutually impacted BAs and TOPs. The requirement for strategies be included in each Plan and implemented for coordination appears to stop short of the above stated goal. It is also confusing: does this include coordination both in the Plan development and the actual implementation during an Energy Emergency? How should enforcement respond to an instance where one entity reaches out to another, but is unable to get a response or cooperation? The District suggests Parts 1.3 & 2.5 remain the same, but that the Reliability Coordinator be tasked as part of the approval process to affirm coordination has been achieved. Please refer to comments responding to question 3.
No
The District agrees with the concept, but finds there are no defined elements the RC should follow before issuing approval or disapproval of an Emergency Operating Plan (Plan). Please see comment to question 2. The SDT's intent appears not to encompass a goal of assuring each plan is compliant before approval. Rather, the intent appears merely to establish an opportunity to reduce risk to the BES. While the District does not believe the RC should be placed in the compliance auditor's role, there is concern that the approval process will greatly vary depending upon the particular RC, or the amount of time available to review Plans. While a 30-day allowance to review a single Plan for approval or disapproval may be reasonable, the SDT should consider instances where the RC will need to review many Plans together as an interweaving coordinated effort for a large operational footprint. Further, the SDT should consider establishing minimum Plan review objectives before Plan approval is granted. Otherwise, the RC will be allowed to rubberstamp Plans with little or no serious review. The District proposes the following be considered: 1) require the RC to review each submitted Plan and document findings. 2) Approval or disapproval of a Plan is based on the findings from the review. 3) Allow the RC to issue conditional approval subject to further review when additional time is required to analyze coordination with other impacted TOPs and BAs. 4) Require the RC to retain an up-to-date archive of all Plans within its footprint to assist its review for coordination between plans and application for lessons learned. 5) Require the RC to recall an approved Plan when it discovers a weakness or gap, and give notice to the affected entity why the Plan has been recalled. 6) Require entities that have been given notice of a recalled Plan to submit a revised Plan for approval. 7) Consider whether or not the RC should be given expressed final authority to resolve coordination issues between plans.
Yes
The District defers to BA comments.
No
R1 contains a typo in the High VSL column: "The Transmission Operator [failed to have] had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include either Part 1.1 or Part 1.3." R3 has no provision other than untimely approval or disapproval. It appears in the instance the RC runs out of time to review, a simple stamp of approval on day 29 or 30 is sufficient for compliance. If the goal is to simply

require the RC to issue approval or disapproval (without any quality control of the review), this then appears to extend a substantial amount of trust without verification.
The District feels the SDT is progressing in the correct direction. However, concerning the changes made to Requirement R4, the District recommends the SDT review word usage of “practical” as it can be easily misunderstood. Its usage in “as soon as practical” is equivalent to “as soon as useful.” If this is the intent of the SDT, the District recommends “as soon as useful” due to the fact that “practical” is often confused with “practicable,” i.e., as soon as possible. The District appreciates the desire not to engulf BAs and TOPs with excessive or nuisance Emergency notices.
Individual
Jo-Anne Ross
Manitoba Hydro
Yes
Yes
Yes
Yes
Yes
Yes
Individual
Brett Holland
Kansas City Power & Light
Individual
Kayleigh Wilkerson
Lincoln Electric System
Yes
Yes
Yes
Yes
No
The 2nd part of the High VSL for Requirement R1 should read: "The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include either Part 1.1 or Part 1.3." Additionally, the 3rd part of the High VSLs for R1 and R2 indicate that an entity is non-compliant upon failure to maintain its Emergency Operating Plan. In consideration that R1 and R2 do not specify a maintenance cycle for the Emergency Operating Plan, how would this VSL be evaluated? As an example, an entity may decide to review their Plan on a two-year cycle but an auditor could view a maintenance cycle greater than once per calendar year as a failure to adequately maintain the Plan. To simplify the VSL, recommend removing the third part altogether.

Group
MRO NERC Standards Review Forum
Joe DePoorter
Madison Gas & Electric
Yes
Yes
R1.3 and R2.5 state that strategies are required to coordinate Emergency Operating Plans with impact TOPs and BAs. The NSRF questions this. Each TOP or BA can have strategies between impacted TOPs and BAs and the RC can still disapprove of their coordinated plans, per R3. The amount of effort between TOPs and BAs “prior” to submission to the RC could be rather great. The impacted entities may have perfectly coordinated plans but the RC could still disapprove them. The NSRF understands that the BA’s and TOP’s plans need to support the RC’s plans. This will assure a steady state system during emergencies. R1 and R2 already prescribe that each TOP and BA have RC approved Emergency Operating Plans. Thus, we recommend that R1.3 and R2.5 be deleted. The RC has totoal control over their RC area and are best suited to approve all Emergency Operating Plans within their area of responsibility. R1.2.6 speaks of “coordination” between the TOP’s manual Load shedding plans and the use of automatic Load shedding. This is clearly stated in the Rational box for R1.2.6 but the Requirement reads differently. Recommend R1.2.6 to read: “Operator-controlled manual Load shedding plan coordinated to minimize the over lapping with the use of automatic Load shedding; . Or read similar to the recommendation of R2.4.8. Another possible solution would be the following wording of “Operator-controlled manual and automatic load shedding programs have sufficient separation of loads between the programs to perform each of their respective intended plan functions”. R2.4.8 reads similar to R1.2.6. But the Rational boxes are different, recommend that both Rationals read the same with the addition of “The reference is not intended to require coordination with other entities” be added to R1 Rational box.
Yes
The NSRF believes that with the RC approving Emergency Operating Plans, that they are “coordinating (align) Emergency Operating Plans within their RC area. This approveal process will reduce the risk of instability during emergencies.
Yes
Yes
Yes
R1.2.3, Transmission is capitalized and generation is not, not sure if this is a type-o or not. R2.4.6, Customer fuel switching. The NSRF questions why this should be in an Emergency Operating Plan, since the customer will most likely be under 2.4.7, Demand response. As a BA, there are contracts with customers and if they elect to not be a signatory to those contracts, they always have the right to drop utility power and go on their owned and operated generation during the time of no utility power. Plus customers that own their own generation are excluded from the NERC Standards if they meet Exclusion E2 of the new BES definition. Recommend R2.4.6 be deleted from the R2. In addition to the above justification, there is no clear definition of “customer”. Could a customer be a single house hold that has a back up generator legally tied to their main circuit panel? This is another reason why R2.4.6 should be deleted.
Group
FirstEnergy Corp
Richard Hoag
FirstEnergy Corp
Individual
Denise Lietz
Puget Sound Energy

No
It is difficult to determine whether the language in parts 1.3 and 2.5 requires the coordination of the plans during the development phase, during the implementation phase or both. The previous R3 appears to have addressed coordination during the development phase, but the structure of the current language seems to be more suited for coordination during the implementation phase. If the second option is the case, the SDT should consider revising the language to something like "Strategies for coordinating the implementation of Emergency Operating Plans…"
No
Imposition of an RC approval process for these plans will impose a significant burden on the RCs, as well as on the BAs and TOPs. It would be better to model the required coordination after the approach implemented in IRO-010 – where the RC specifies additional requirements for the plans and the BAs and TOPs are required to comply with those specifications. This approach will allow an RC to address specific interconnection and RC area issues, but does not impose the significant administrative burden of coordination with each BA and TOP within its area.
Yes
As defined in the NERC Glossary of Terms, the term "Emergency" is quite broad. As the standard is currently structured, an entity's Emergency Operating Plan could be implemented regularly, with a resulting need to demonstrate compliance with the plan's requirements during many events, regardless of the events' potential to significantly impact the BES. To address this impact, the SDT could consider limiting the instances when an entity is required to implement the plan in some way – either by using other defined terms that include a measure of significance (for example, a combination of "Energy Emergency" and "Adverse Reliability Impact" (as that term was approved by the BOT on 08/04/2011) would reflect more significant events) or by listing the types of events that require implementation of the plan (instances of manual or automatic load shedding, entry into an energy emergency condition, etc.).
Group
Peak Reliability
Jared Shakespeare
Peak Reliability
Yes
Yes
Yes
Yes
BA requirement is still in R2.2
1. Requirement 2.3: It is unclear whether this Requirement is for the BA to define criteria or simply reference criteria in Attachment 1. If the former, it appears inconsistent with the role of the RC in declaring EEAs. If the latter, it's unclear why this is necessary because the criteria already exists. 2. Requirement 3: a. The Standard Drafting Team stated "While plan approval by the Reliability Coordinator is not specifically required by the directive in Order No. 693, the EOP SDT believes that approval by the Reliability Coordinator reduces risk to reliability of the BES." Please provide further clarity on the approval role of the RC. Several of the sub-requirements listed for BA R2, 2.4 are of such detail that the RC could not validate and therefore it is unclear how the RC would approve. Validation of R2.4 would be a Compliance Enforcement Authority function rather than an RC function. b. It appears there should there be a time delay after RC approval for each TOP/BA plan to be implemented in order to allow time for operators to be familiar with entity plans similar to the

EOP-006-2 R6. 3. If a BA is also a TOP, is only one Emergency Operating Plan required which cover all the requirements for both? Please clarify. 4. There should be an annual review like there is for EOP-005/EOP-006. If annual or other scheduled periodic review and submittal becomes required, need verbiage on mutually agreeable schedule (reference EOP-005-2 R3).
Individual
Richard Vine
California ISO
Individual
Terry Harbour
MidAmerican Energy
Yes
No
R1.3 and R2.5 state that strategies are required to coordinate Emergency Operating Plans with impact TOPs and BAs. The NSRF questions this. Each TOP or BA can have strategies between impacted TOPs and BAs and the RC can still disapprove of their coordinated plans, per R3. The amount of effort between TOPs and BAs “prior” to submission to the RC could be rather great. The impacted entities may have perfectly coordinated plans but the RC could still disapprove them. The NSRF understands that the BA’s and TOP’s plans need to support the RC’s plans. This will assure a steady state system during emergencies. R1 and R2 already prescribe that each TOP and BA have RC approved Emergency Operating Plans. Thus, we recommend that R1.3 and R2.5 be deleted. The RC has totoal control over their RC area and are best suited to approve all Emergency Operating Plans within their area of responsibility. R1.2.6 speaks of “coordination” between the TOP’s manual Load shedding plans and the use of automatic Load shedding. This is clearly stated in the Rational box for R1.2.6 but the Requirement reads differently. Recommend R1.2.6 to read: “Operator-controlled manual Load shedding plan coordinated to minimize the over lapping with the use of automatic Load shedding; . Or read similar to the recommendation of R2.4.8. Another possible solution would be the following wording of “Operator-controlled manual and automatic load shedding programs have sufficient separation of loads between the programs to perform each of their respective intended plan functions”. R2.4.8 reads similar to R1.2.6. But the Rational boxes are different, recommend that both Rationals read the same with the addition of “The reference is not intended to require coordination with other entities” be added to R1 Rational box.
Yes
Yes
No
MidAmerican is not supportive of shedding load to preserve Operating Reserves for an EEA 3 event as presently included in Attachment 1, Section 3.2 of the standard. MidAmerican believes that other actions can and should be taken prior to declaring EEA3 and / or shedding load just to maintain operating reserves. The revisions to EEA3 could lead to an inappropriate number of EEA3 events being called and possibly inappropriate load shedding. Any changes that could lead to inappropriate load shedding must be carefully considered.
Yes
: R1.2.3, Transmission is capitalized and generation is not, not sure if this is a type-o or not. R2.4.6, Customer fuel switching. The NSRF questions why this should be in an Emergency Operating Plan, since the customer will most likely be under 2.4.7, Demand response. As a BA, there are contracts with customers and if they elect to not be a signatory to those contracts, they always have the right to drop utility power and go on their owned and operated generation during the time of no utility power. Plus customers that own their own generation are excluded from the NERC Standards if they meet Exclusion E2 of the new BES definition. Recommend R2.4.6 be deleted from the R2. In addition to the above justification, there is no clear definition of “customer”. Could a customer be a single

house hold that has a back up generator legally tied to their main circuit panel? This is another reason why R2.4.6 should be deleted.
Individual
Josh Smith
Oncor Electric Delivery LLC
Yes
Yes
Yes
Yes
Yes
Yes
Group
Dominion
Connie Lowe
Dominion
Yes
For consistency with the Rationale listed for R2 pertaining to "any Parts of Requirement R2 are not applicable", a similar statement should be listed under the rationale for R1. Dominion suggests adding; If any Parts of Requirement R1, Part 1.2 are not applicable, the Transmission Operator should note "not applicable' in their plan.
Yes
We agree that Emergency Operating Plans should be coordinated.
Yes
We agree that the SDT met the FERC directive and we also cite the comments of many as providing justification requiring such approval. In some areas, generation scheduling, dispatch and outage approval is done by an entity registered solely as BA while in others it is done by an entity that may be registered as BA and TOP. In others it is done by an entity registered as BA, TOP and RC. In order for this standard to accommodate these variations, we support a requirement that, at a minimum, requires the RC insure the individual plans are coordinated such that they can be utilized in an aggregated manner when necessary to maintain relibiability within the RCs reliability area. We could make similar statements relative to manual load shedding. BAs typically do not have field personnel and therefore must rely upon manual load shed plan 'owned' by an entity with such personnel (typically DP). In this case, it is appropriate for the BA's load shed plan to consist of contacting that entity (or entities) and directing a specified amount of load be shed within a defined amount of time. It is also appropriate for the BA's load shed plan to consist of contacting its RC and requesting that a specified amount of load be shed within a defined amount of time. In this example, the RC would then have to contact one or more entities directing them to shed a specified amount of load be shed within a defined amount of time. In either case, the RC would have reviewed and approved the Emergency Operating Plan developed by each BA and TOP within its reliability area based upon insuring that these plans are coordinated as necessary.
Yes
Yes
Dominion agrees with the change, but for additional clarity with an EEA3 (EEA 3— Inability to meet Operating Reserve requirement or Firm Load interruption is imminent or in progress.) where you are

NOT meeting Operating Reserves, Dominion suggests rewriting 3.2 to read as; Operating Reserves; such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement.
Yes
R2 – For consistency with Part 1.1; remove ‘and implement’ from 2.1 (this is not struck on the redlined version, but it does show that it has been removed on the clean version). R2 – For consistency with R1; the content of 2.2 and 2.3 should be moved as sub parts below 2.4 instead of included as “stand alone” parts 2.2 and 2.3. R2- The requirement appears to use a newly capitalized term “Capacity”. This term is not included in the NERC Glossary of Terms currently posted. If the intent is to use the existing defined terms, Capacity Emergency and Energy Emergency, then the SDT needs to write the requirement accordingly.
Group
SPP Standards Review Group
Robert Rhodes
Southwest Power Pool
Yes
However, as written Requirement R1, Part 1.2.6 requires that the manual Load shedding plan minimize the use of automatic Load shedding. We believe the intent of the drafting team is for the requirement to state that the manual Load shedding plan should minimize the shedding of Load contained in the automatic Load shedding program. Otherwise the requirement reads that automatic Load shedding is a part of the manual Load shedding plan. We suggest the following language change for clarification: ‘Operator-controlled manual Load shedding plan coordinated to minimize the amount of load designated in both the manual Load shedding and automatic Load shedding programs;’. This same comment would also apply to Requirement 2, Part 2.4.8.
Yes
Yes
Yes
No
By making this change, the drafting team is requiring deficient Balancing Authorities which can not maintain their Operating Reserve obligations to ‘be able to’ shed firm Load in order to maintain its reserve obligations. We seek clarification from the drafting team on whether the deficient Balancing Authority is required to actively shed load in order to maintain its reserves or only needs to have the capability to shed load to maintain its reserves. The drafting team has proposed this significant change without providing sufficient justification for the change. The proposed BAL-002-2 is referenced as the driver for this specific change. However, by our reading of the last posted version of BAL-002-2, R2 the responsible entity is given an exemption from needing to maintain its reserves if it has experienced a Contingency or is in an EEA 2 or EEA 3. The proposed language in EOP-011-1 is in direct conflict with this language. The exemption holds equally well for EEA 2 and EEA 3. So why change? Why move the Operating Reserve clause to EEA 3? We strongly recommend that the drafting team put the Operating Reserve clause back under EEA 2 where it belongs.
No
The 2nd part of the High VSL for Requirement R1 should read: ‘The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include either Part 1.1 or Part 1.3.’ Requirements R1 and R2 require the Transmission Operator and Balancing Authority to develop, maintain and implement an Emergency Operating Plan. The High VSLs for both R1 and R2 hold the responsible entity as non-compliant if the entity failed to maintain its Emergency Operating Plan yet nothing in the requirements or the supporting documentation provide any guidance on what needs to be done to

satisfactorily ‘maintain’ the plan. The industry needs to know what is expected in order to demonstrate compliance with this requirement. Additionally, the use of the term’implement’ in these requirements apparently has a different meaning than in other reliability standards. In other standards when a plan, process or procedure is to be implemented, it means that the plan, process or procedure is to be issued, be readily available for operator use, and for operators to be trained on the plan, process or procedure. In EOP-011-1, implement means the plan was activated due to an operating condition which requires initiation of the EOP. The drafting team needs to be consistent with other drafting teams such that confusion is minimized. We believe the drafting team can correct this inconsistency by adding two new requirements, one for the TOP and one for the BA, which requires the responsible entity to activate, or initiate, its plan when an Emergency condition arises. For example, the drafting team is referred to EOP-005-2, R7 which requires the responsible entity to execute its restoration plan when a blackout occurs. In fact, EOP-005-2 is a good example of how to incorporate develop, maintain and implement into a reliability standard. The redline version of the 1st part of the Severe VSL for Requirement R2 is missing the following lead-in phrase: ‘The Balancing Authority had a Reliability Coordinator-approved…’ Change the ‘Transmission Operator and Balancing Authority’ language in the VSLs for Requirement R3 to ‘Transmission Operator or Balancing Authority’. Also, the Reliability Coordinator is non-compliant in the Severe VSL for Requirement R3 if it fails to approve/disapprove a submitted Emergency Operating Plan within 60 days or if it fails to approve/disapprove the submitted plan at all. Why not combine the two parts into a single VSL which states: ‘The Reliability Coordinator failed to approve or disapprove, with stated reasons for disapproval, a Transmission Operator or Balancing Authority submitted or revised Emergency Operating Plan within 60-calendar days.’ Please add calendar to the 30, 40, 50, etc. and hyphenate. For example, 30-calendar days, 40-calendar days, 50-calendar days, etc. How does the drafting team propose to measure ‘as soon as practical’ in the High VSL for Requirement R4? Since no notification was made in the Severe VSL for Requirement R4, delete the redundant ‘as soon as practical’ phrase from the Severe VSL. Delete the ‘has’ in ‘…alert has ended.’ at the end of the Moderate VSL for Requirement R5. The High VSL for Requirment R5 requires the Reliability Coordinator to conduct conference calls as necessary to communicate System conditions. This specific item has been pulled from Attachment 1 which is referenced in Requirement R5. It is not specifically listed in the requirement and is one of a mirade of items contained in Attachment 1. Why has the drafting team chosen this specific item to single out in the VSL and not include it in the requirement? The need for the emphasis is questioned especially in light of recent work in Project 2014-03 associated with IRO-014-3, R3 which is currently posted for industry comment and ballot. Requirement 5 will be redundant with IRO-014-3, R3 if it is approved. We suggest the drafting team rethink the need for this emphasis and more closely coordinate with the TOP/IRO Revisions drafting team in Project 2014-03.
Shouldn’t the term “energy emergency” as it appears in the 5th line of the Rationale Box for its definition be capitalized? Also in the Rationale Box for the definition under IRO-005-3.1a, the SDT states that IRO-005-3.1a is being revised under Project 2014-03 TOP/IRO Revisions. This is not the case. Project 2014-03 is not working with IRO-005. The IRO Five Year Review Team moved requirements regarding notification from IRO-005-3.1a to IRO-008-1 and recommended retiring IRO-005. Project 2014-03 has made additional changes to IRO-008-1 but the changes proposed by the IRO Five Year Review Team have been incorporated into the latest revision of IRO-008-2 by Project 2014-03. The term energy emergency is not in either version of IRO-008. (This same comment applies to a similar section in the Proposed Definitions for the NERC Glossary of Terms document.) Terms such as 30-calendar days should be hyphenated. How does the drafting team propose to measure ‘as soon as practical’ in Requirement R4? The following comments are directed toward Attachment 1. Changing the ‘should’ to ‘shall’ in the sentence in Section A.2 creates a conflict in that the Reliability Coordinator is now required to hold conference calls but the conditions under which those calls are to be held are not specifically defined by the phrase ‘as necessary.’ We recommend the drafting team return the language to the original language or provide the Reliability Coordinator with a list of conditions which would necessitate such calls. Also, see our comment in response to Question 6 regarding additional information on this issue. In the 5th line of the Introduction under Section B. EEA Levels, change ‘standard’ to ‘standards’. Insert an ‘an’ between ‘During’ and ‘EEA2’ in the line between the last bullet under Circumstances under Section B.2 and 2.1. Insert ‘to service’ between the ‘return’ and the ‘the’ at the end of the 2nd line of B.2.4. Insert an ‘an’ between ‘During’ and ‘EEA 3’ in the line between the bullet under Circumstances under Section B.3 and 3.1. See our comment on 3.2 in Question 5 above. Add RCs to B.3.3 to be

consistent with B.2.2. Replace ‘SOLs or IROLs’ with ‘SOL or IROL’ in the 3rd line of B.3.5. The following comments are directed toward the Technical Justification document. The designation for footnote 4 should be a superscript in the next to last line on Page 3. The 2nd and 3rd bullets under EOP-002-2 are actually a continuation of the 1st bullet. The bullets, not the text, need to be deleted.
Group
Tennessee Valley Authority
Dennis Chastain
Tennessee Valley Authority
Group
DTE Electric
Kathleen Black
NERC Training & Standards Development
No
In 1.2.6 and 2.4.8, the "Operator-Controlled" language is acceptable but "coordinated to minimize the use of automatic Load sheding" is vague compared to the intent of the requirement as explained in the Rationale. Since the intent is to reduce the overlap between manual and automatic Load shedding schemes, why not state it clearly in the requirement? Consider changing 1.2.6 and 2.4.8 to "Operator-controlled manual Load shedding plan coordinated to minimize the overlap with automatic Load shedding schemes."
Yes
Yes
Yes
No
SDT did not provide rationale associated with this change.
No
The Severe VSL for R4 is semantically the same as the High VSL for R4. Suggest removing "as soon as practical" from the Severe VSL for R4.
R1: The TOP should not be responsible for cancellation of generator outages. This function should remain being assigned to the BA. The current standard NERC EOP-002-3.1 has the BA postponing equipment maintenance. EEA2 Section 2.5.2: Demand-Side Management is a term defined in the NERC glossary. Ensure the hypen is in place for both uses of the term. Attachment 1B Introduction, first sentence: change "four" to "three".
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
LG&E and KU Energy, LLC
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.
Yes
Requirement R3 specifies the amount of time the RC has to approve a BA or TOP’s EOP; however, it does not specify the amount of time a TO or BA has to revise and resubmit the EOP in the event that an RC does not approve the initial submission.
No

Operating Reserve requirement OR Firm Load interruption is imminent or in progress.” The circumstance description in section 3 states that the “Requesting BA is unable to meet Operating Reserve requirements AND foresees a need for possible interruption of Firm Load.” We feel that the STD inadvertently used the word “or” in the heading for Attachment A, section 3. We recommend that the heading be changed to the following in order to make it consistent with the circumstance description in section 3. “EEA 3 – Inability to meet Operating Reserve requirements and firm Load interruption is imminent or in progress.” Note that firm load is not a defined term and should not be capitalized. If those changes are made, we would agree with the Operating Reserves being moved from EEA 2 to EEA 3.
Comment on Requirement 2, section 2.4.6 – We suggest the removal of “Customer Fuel Switching” from the list. It is unclear what a strategy titled “Customer Fuel Switching” would entail. Comment on Attachment A, section B.2.5 – The first sentence begins with “Before declaring an EEA 3, the requesting BA must…” This makes it sound as though the BA can declare an EEA 3. The sentence should read, “Before requesting an EEA 3, the BA must…” Comment on Attachment A, section B.2.1 – This section is preceded by the sentence, “During an EEA 2, RCs and BAs have the following responsibilities:” The first sentence of 2.1 states that, “The requesting BA shall communicate its needs to other BAs and market participants,” but it does not describe how the BA is to make this communication. It sounds as though this is a real time communication between the requesting BA and market participants (PSEs) but over what medium, and what obligation do the PSEs have to proactively look for communications from requesting BAs? Market participants (PSEs) may not have access to the RCIS website. Comment on Attachment A, section B.3.4.1 – The words “must agree that” in the first sentence of this section should be removed to reflect that the requesting BA does not have any options in the defining the prerequisites for SOL/IROL revision. We recommend the following change: “The requesting BA will, upon notification from its RC of the situation, take whatever actions are…” Comment on Attachment A, section B.2.5.1 – The mention of “all available generation units” is unnecessary as this is previously mentioned as a circumstance of an EEA1 in section B.1. Comment on Attachment A, section B.2 – Is this intended to mean that operating reserves should be maintained while the entity can’t meet the customer’s expected energy requirements? Operating reserves would not be maintained at the expense of cutting firm load.
Individual
Dave Willis
Idaho Power Co.
Yes
The addition of Operator-Controlled does not seem to change the intent of the requirement. The extent of operator control may be just limited to activating the load shedding application in EMS. I don't agree or disagree with the change.
Yes
I was unable to find the requirement for coordinating Emergency Operating Plans with impacted Balancing Authorities and Transmission Operators. Requirement 1.3 says " Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities" this seems a little vague.
No
The new R3 says that the RC will approve or disapprove the submitted plans. If they are charged with approving a plan it seems there should be some requirement to ensure that they are coordinated. With the elemination of the old R3 the approval seems incomplete. The Reliability Coordinator must be able to access all BA and TOP Emergency Procedures and have the ability to ensure that procedures are coordinated and do not conflict with each other. However to require the Reliability Coordinator to Approve all Emergency Operating plans will increase the burden on all entites involved with little increase in system reliability. IPC System Planning like that the change assumes some level of coordination between the RC and TOPs.
Yes
Yes
It keeps with the existing EEA1, EEA2 & EEA3 instead of interjecting an EEA4 in to the standard.

Yes
IPC Grid Operations Training does not believe administrative tasks should have a high VSL attached to it.
Individual
Andrew Pusztai
American Transmission Company LLC
Yes
Yes
Yes
Yes
N/A
ATC has no comment regarding the VRFs and VSLs.
ATC agrees with the SDT's addition of the term "Operator-controlled" preceding the language "manual Load shedding" in Requirement R1, Sub-Requirement 1.2.6., however, ATC offers the following recommendations for added clarity and to further align the requirement to the rational given for Requirement R1. Currently Drafted Sub-Requirement from Standard EOP-011-1 (text below) 1.2.6. Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding; --- ATC recommended revisions to Sub-Requirement R 1.2.6: (1) ATC recommends adding the text "Loads with" after "the use of" in Sub-Requirement 1.2.6. above. It would read as follows: R 1.2.6 "Operator-controlled manual Load shedding plan coordinated to minimize the use of Loads with automatic Load shedding"; (2) Alternatively, ATC recommends the following change be made to R1.2.6 where "use of" is replaced with "overlap with". It would read as follows: R 1.2.6 "Operator-controlled manual Load shedding plan coordinated to minimize the overlap with automatic Load shedding; ATC believes either of these recommended revisions provides clarification regarding the SDT's intent for Sub-Requirement 1.2.6, as defined in the Rationale for Requirement R1.
Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
Individual
Karin Schweitzer
Texas Reliability Entity
Yes
No
As currently written, Requirements R1 and R2 do not explicitly state that the BA and TOP shall coordinate their EOPs with impacted BAs and TOPs. R1.3 and R2.5 state that the TOP and BA, respectively, shall have EOPs that include "Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities." The requirement to have a strategy is not the same as requiring the TOP and BA to coordinate with impacted BAs and TOPs. As such, the requirement to coordinate from the removed Requirement R3 is no longer covered in the standard. Therefore the failure to coordinate is not enforceable and the reliability benefit is lost. Texas Reliability Entity, Inc. (Texas RE) recommends the EOP SDT consider adding a requirement as follows: "Each Balancing Authority and Transmission Operator shall coordinate their Emergency Operating Plans with the other Balancing Authorities and Transmission Operators in their Reliability Coordinator Area to assure that the plans are compatible and support reliability in the Reliability Coordinator Area." Adding a requirement to coordinate would also require an addition to

the VSL. Texas RE suggests the SDT add a Severe only VSL for failure to coordinate with all BAs and TOPs in their RC Area.
No
RC approval of the TOP EOPs places an unnecessary burden on both entities, particularly in cases where plan updates may be administrative in nature. Also, by approving the TOP EOPs, the RC may be accepting an unnecessary legal risk by accepting a plan as sufficient and adequate to ensure reliability when they do not necessarily have detailed knowledge of the systems for which the EOPs were developed. The RC review, if any, should only ensure that the emergency plans are coordinated and compatible with the overall RC EOP and other entity plans in the RC area.
Yes
Texas RE agrees with this revision. The requirement for a TOP to notify its RC of actual or expected emergencies is still in the draft TOP-001-3, as R8.
Yes
No
1)R1 High VSL appears to contain a copy/paste mistake in the second “OR” statement which states the TOP FAILED to have an RC approved EOP but goes on to say “but failed to include either Part 1.1 or Part 1.3.” Is the intent to capture that the TOP did have an approved RC plan “but failed to include either Part 1.1 or Part 1.3” rather than the TOP did not have a plan? The Severe VSL for R1 (second “OR” statement) covers the TOP failure to have an RC approved plan. Texas RE requests clarification from the SDT. 2) Texas RE recommends that R2 VSLs for all levels should specifically include the sub-parts of 2.4.1. Although it could be reasonably interpreted that the sub-parts of 2.4.1 are included, not explicitly stating they are included could pose issues in the enforcement realm (i.e., they would be unenforceable.) As currently written, a Registered Entity could include generating resources in its EOP without including those four sub parts (2.4.1.1.-2.4.1.4) and still be compliant. Texas RE recommends the EOP SDT add the phrase “including sub-parts of 2.4.1” immediately after “Sub-Parts 2.4.1.-2.4.9” in all the VSL levels.
Texas RE recognizes the amount of work the SDT has put into this standard and applauds the team for successfully combining the existing Emergency Operations requirements into one single Standard. Much of the ambiguity has been eliminated and various inputs have been addressed well. However, Texas RE has a few concerns with the current draft which prompt a negative vote at this time. 1) The main focus of this standard appears to be energy and capacity emergencies. Are there other types of emergencies that need to be covered by emergency plans? For example, does the standard need to cover requirements if a TOP may need to declare a Transmission emergency if it is unable to mitigate an IROL or SOL violation? 2) Requirements R1 and R2: EOPs are critical to the reliability of the BES and assurance that the plans are maintained is necessary. The mapping document on the 2009-03 project page shows that the requirement for a time based review/update of EOPs (from EOP-001-2.2.1b, Requirement R5) has been translated to EOP-001-1, Requirement R1. However, the draft standard does not include a requirement for a TOP or BA to review/revise their EOPs on a specified periodicity. Therefore it is not measurable. Texas RE recommends the EOP SDT adding the following phrase to both R1.4 and R2.6: “Revise and review the EOP as needed but no less than annually.” 3) The language for Requirements R1.2.6 and R2.4.8 states that operator-controlled Load shedding shall be coordinated to minimize the use of Automatic Load Shedding. That language is not in synch with the Rationale for Requirement R1 which states the goal is minimize the manual use of Loads armed for automatic Load shedding; recognizing that complete exclusion may not be possible. Texas RE recommends the EOP SDT revise the language in Requirements R1.2.6 and R2.4.8 to the following: “Operator-controlled manual Load shedding plan coordinated to minimize the use of Loads armed for automatic Load shedding;” 4) Requirement R4: While agreeing with the change of practicable to practical in the requirement, Texas RE asserts that omitting a required notification “not to exceed” date allows a potential reliability gap. RCs, BAs, and TOPs need to know that Emergency notifications have taken place even if they were not directly involved in the Emergency, and they need to know relatively quickly. This communication can be assured by the addition of “but no later than seven days after the end of the Emergency” after “as soon as practical”. The addition would require a corresponding adjustment to the VSL. In addition, the Rationale for R4 states that it was an existing requirement in EOP-002-3.1 for BAs. It appears that the EOP-002-3.1 requirement being referenced here is Requirement R3, which required a BA

experiencing an operating capacity or energy emergency to communicate system conditions to its RC and neighboring BAs. The requirement did not restrict the required communication to “impacted” BAs. Texas RE recommends the EOP SDT consider removal of the phrase “other impacted” RCs, BAs and TOPs and replace it with “neighboring” RCs, BAs and TOPs. Replacing “impacted” by “neighboring” is important since, among other reasons, the Emergency may have been resolved efficiently in that instance, but conditions may still exist for the Emergency to reoccur and the potential next Emergency may involve more TOPs and BAs than the previous Emergency. 5) Requirement R5: R5 states that an RC shall initiate an Energy Emergency Alert (EEA) when a BA in its area has a potential or actual Energy Emergency but does not address the RC responsibility in the event the BA has a Capacity Emergency. Requirement R2.2 requires that a BA having a Capacity Emergency notify the RC of that Emergency. Texas RE requests clarification regarding the RC responsibility to take some action in the event of a BA Capacity Emergency.
Individual
Rich Salgo
NV Energy
No
The continued inclusion of the concept of coordination (or separation) of the Operator-Controlled manual Load shedding with the automatic underfrequency Load shedding is inappropriate for reliability, and the vague and ambiguous language raises auditability concerns. Underfrequency load shedding schemes are carefully coordinated across the Region to ensure that prescribed percentage steps of an area’s load are shed at specific system frequency levels. The subrequirements R1.2.6 and R2.4.8 both convey that an entity should strive to minimize any overlap between its manual load shedding circuits and those that will be shed automatically by underfrequency. This approach results in an undesirable skewing of the percentage of an entity’s load that will be shed by its underfrequency program. Specifically, the shedding of an entity’s load manually, if the load is completely separate from the underfrequency circuits, will increase the percentage of remaining load that is to be shed by the entity’s underfrequency program, jeopardizing the desired balance of the Regional underfrequency program coordination. The sub-requirements R1.2.6 and R2.4.8 are written with vague language. Taking the parent Requirements R1 and R2 into account, the entity is to develop maintain, and implement a Plan, which at a minimum, shall include: Strategies to prepare for and mitigate Emergencies including: Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding. As written, it is unclear what evidence would demonstrate adequacy with satisfaction of these requirements. The Rationale statements for R1 and R2 speak to the Entity evaluating their automatic load shedding schemes and coordinating so that overlapping use of Loads is avoided to the extent reasonably possible, but there is no clarity as to what threshold an auditor would accept for the resultant overlap. Particularly, given the consequence of over-shedding automatic underfrequency loads if one were to fully segregate manual load shed circuits from automatic load shed circuits as explained above, it does not appear that these two sub-requirements promote BES reliability. We recommend removal of both sub-requirements R1.2.6 and R2.4.8, and addressing these matters in relevant NERC guidance documents.
Yes
Yes
We agree that the inclusion of the RC is achieved through the proposed provision of approval of the emergency plans. The Standard, however, is noticeably silent on the protocols that would be expected in the event that the RC is unable to approve one or more Plans, either the Transmission of Energy Emergency Plans. For instance, if the RC reviews a Plan but finds fault in it, how will compliance with the 30-day approval time limit be achieved? Further, what is the status of compliance of the Entity whose submitted Plan is returned for revision? There would be a period of time wherein the Entity may be operating under its Plan without attaining approval from the RC. Is the Entity in jeopardy of non-compliance by operating under an unapproved Plan? The VSLs don’t address this possibility.
Yes
No

Traditionally, we have seen the EEA-1, -2, and -3 as an orderly progression in deficiency. Level 1 was characterized as all resources being in service, yet reserve requirements continuing to be met; Level 2 is characterized by an erosion in the resource/load balance to the point that operating reserves were being impacted; and finally, Level 3 indicates that firm Load may no longer be able to be served. The movment of “Operating Reserves” into EEA-3 seems to remove the distinction between EEA-1 and EEA-2 and makes an EEA-3 a significant step change in system condition from that of the EEA-2. The rationale for this change may be appropriate, and the change may be necessary; however, we are unable to find an explanation of the need for the change or what it is intended to accomplish. Also, we are concerned with the premise that the entity should shed some of its load in an EEA3 in order to maintain reserves. This appears to be contrary to our collective reliability goal of preserving service. Shedding the load for the sole purpose of retaining adequate reserves will unnecessarily deter from our reliability charge. Rather than shedding load pre-contingency, reliability is best served by continuing to serve the load and implementing load shed immediately following the contingency.
We commend the drafting team on their work to consolidated these multiple standards, streamlining the compliance requirements. Our negative vote on this draft stems from the concerns around the required coordination of manual and automatic load shedding as well as the consequences created with the language changes in the EEA Level 2 and 3 criteria.
Group
JEA
Tom McElhinney
JEA
Yes
No
The plan should not be required to be approved by the RC. We do not have a problem coordinating with them and providing them a copy as current standards require.
Yes
R1&R2 should state that only "applicable" parts need to be included. Voltage control should not be part of the emergency plan and is already covered by standards TOP004-R6 and VAR001-3 R1.
Group
SERC OC Review Group
Stuart Goza
TVA
Yes
For consistency with the Rationale listed for R2 pertaining to “any Parts of Requirement R2 are not applicable”, a similar statement should be listed under the rationale for R1. The SERC OC Review Group suggests adding; If any Parts of Requirement R1, Part 1.2 are not applicable, the Transmission Operator should note “not applicable’ in their plan.
Yes
The SERC OC Review Group agrees that Emergency Operating Plans should be coordinated.
Yes
Yes
No

The SERC OC Review Group feels there is still lack of understanding around the use of Operating Reserves vs. Contingency Reserves and believe further work is needed to provide better clarity. Changing the current definition of EEAs by moving the term Operating Reserves may not solve the conflict with BAL standards and adds unneeded complexity to this standard. Operating Reserves include Contingency Reserves and clarity should be added in the use of these terms in the Attachment. For Section 3.2 of the Attachment, should the wording be ‘Operating Reserves are being used’ or ‘Operating Reserves can be used’?
Yes
R2 – For consistency with Part 1.1, remove ‘and implement’ from 2.1 (this is not struck on the redlined version, but it does show that it has been removed on the clean version). R2 – For consistency with R1, the content of 2.2 and 2.3 should be moved as sub parts below 2.4 instead of included as “stand alone” parts 2.2 and 2.3. R2- The requirement appears to use a newly capitalized term “Capacity”. This term is not included in the NERC Glossary of Terms currently posted. If the intent is to use the existing defined terms, Capacity Emergency and Energy Emergency, then the SDT needs to write the requirement accordingly. Attachment 1 Section A1 - review wording of item 2 for redundant use of ‘request’. Attachment 1 Section 3.4 - SDT should consider that Transmission Owner is more appropriate than Transmission Operator for the subject review of SOLs and IROLs. The comments expressed herein represent a consensus of the views of the above named members of the SERC OC Review Group only and should not be construed as the position of the SERC Reliability Corporation, or its board or its officers.
Individual
Chris Scanlon
Exelon Companies
Exelon agrees with the majority of the substantive changes proposed but encourages the SDT to be as clear as possible with language in the Requirements when drafting the next revision. We note that by removing processes and procedures from R1 for example, and leaving only strategies, an entity may not be able to document the existence of a strategy to implement the Program. The RSAW, for example refers to an auditor verifying that procedures were implemented not that an entity had a strategy. We are generally uncomfortable with the language regarding evaluation of strategies and the use of “at a minimum”. We also note that the Time Horizon for R1 and R2 is Operations Planning (have a plan) and Real Time (implement elements of the plan / strategy). For those Requirements that are Real Time, we question the ability for some of them to be implemented. For example, the requirement to cancel transmission or generator outages in response to an Energy Emergency; the likelihood of bringing a generator or transmission line back into service from an outage in response to a real time emergency is very low. We would like the DT to consider whether this element belongs in an entities plan. We believe the more generic requirements in EOP-001-3 R2 can provide guidance in this area. Also, the requirement to mitigate extreme weather was subject to extensive review and determined not to require a standard. There is NERC Guidance addressing this.
Individual
Scott Langston
City of Tallahassee
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Individual

Bob Thomas and Alice Schum
Illinois Municipal Electric Agency
Group
Seattle City Light
Paul Haase
Seattle City Light
No
Seattle believes that while approval of emergency oeprating plans by the Reliability Coordinator might add BES reliability, it adds more compliance burden than it does add BES reliability. In addition, requiring separate approvals for TOP and BA emergency operating plans may reduce reliability for those entities such as Seattle that are both TOP and BA, because emergency plans that presently integrate TOP and BA activities will need to be made separate purely for compliance purposes. This separation will add unnecessary complexity and duplication to emergency plans, and offers potential for confusion during an emergency situation as opposed to a single integrated plan. Seattle recommends 1) that the SDT follow paragraph 548 of Order 693 as worded, and delete the requirement for approval of emergency plans by the Reliability Coordinator and 2) revise R1 and R2 to allow a single integrated emergency plan for entities that are both TOP and BA (which is common in WECC and represents a substantial fraction of the BAs existing within NERC).
Yes
Seattle offers the following suggestions: For R1.2.1 "Notification to the RC to include current and projected System conditions when experiencing an operating Emergency": to keep the focus on reliability and minimize compliance traps, please add language about notifications such as ‘as soon as practical.’ The focus during an emergency should be on addressing the emergency, not on ensuring compliance activities. To date, auditors at times have focused on the exact timing of notifications while appearing to neglect the larger picture. Additional wording may help avoid such interpretations. For R1.2.2 Voltage Control, please clarify. In the current version of EOP-001 (specifically Attachment EOP-001-0b) voltage control is mentioned in ‘Load Management’ as voltage reductions. The new standard doesn’t give any direction. The ‘Rationale for Requirement’ states: "Requirement R1 Part 1.2. was added to this standard for the Transmission Operator to address strategies to prepare for and mitigate Emergencies using voltage control methods, which could include switching of capacitor and reactor banks, generator reactive output, and the use of synchronous condensers." As such this subrequirement seems like this is a new requirement – not a consolidation of the old requirements. For R1.2.6 and R2.4.8, "Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding": Please provide guidance in this subrequirement or the RSAW as to how such "coordination to minimize" would be evidenced and audited. Alternatively, reword the subrequirement to provide more specificity as to what is intended here. Without additional guidance, this seemingly minor subrequirement could require more evidence than all the other subrequirements together while adding minimal BES reliability benefit. Regarding R1.3 "Strategies for coordinating Emergency Operating Plans with impacted TOPs and BAs" is excessively vague for a world-class Standard. Please provide additional guidance as to what is expected or delete as unecessary. Is an "annual exchange of plans" among impacted TOPs and BAs such a "strategy" or is something further anticipated? As written the subrequirement is reminiscent of a "version 0" best practice: it does not require anything other than that the plan list one or more strategies. It does not require that the strategies be implemented or followed, nor that they are effective or comprehensive strategies. If such activities and characteristics are deemed necessary for BES reliability then they should be required explicitly; if they are not necessary then the subrequirement should be dropped entirely. Standards are not the place for "nice to have" items. In the absence of additional information, Seattle recommends that R1.3 be deleted. The subrequirements of R2.4 for BAs are similarly vague and likewise should be clarified or deleted.

Group
Florida Municipal Power Agency
Carol Chinn
Florida Municipal Power Agency
Yes
FMPA supports the comments submitted by FRCC.
Yes
FMPA supports the comments submitted by FRCC.
No
FMPA supports the comments submitted by FRCC.
Yes
FMPA supports the comments submitted by FRCC.
Yes
FMPA supports the comments submitted by FRCC.
FMPA supports the comments submitted by FRCC.
Group
Duke Energy
Michael Lowman
Duke Energy
No
Duke Energy agrees in concept with R1 and R2, but feel that the language used in R1.2.6 and R2.4.8, should be revised to better reflect what we perceive to be the SDT's intent. We suggest that the language should more closely mirror that which is stated in the accompanying guideline document. We suggest the following revision for R1.2.6, and R2.4.8: "Operator-controlled manual Load shedding plan coordinated to minimize the use of Load shed under automatic Load shedding;"
No
We suggest revising R1.1.3 and R2.5 as follows: "Strategies for coordinating the Emergency Operating Plans of Balancing Authorities and Transmission Operators identified in their Emergency Operating Plan(s). We believe that the use of term "impacted" is too broad in the context of this requirement.
No
Duke Energy is unclear on the justification of requiring an RC to approve the Emergency Operating Plans of a BA or TOP. Is there specific technical justification for the approval, and if so, does it add to the reliability of the BES? We understand that in Order 693, FERC directed that the RC be included as an applicable entity. However, we do not believe that this "inclusion" should necessarily rise to the level of being the approver of a BA or TOP's Emergency Operating Plan. We feel that it would be more appropriate for an RC to be "knowledgeable and aware of all Emergency Operating Plans submitted" by the BA(s) and TOP(s) in its RC area. If the SDT determines that it is essential to have the RC(s) approve Emergency Operating Plan(s) developed by a BA and TOP, then we suggest that criteria be established to provide a consistent, measurable approach throughout the industry.
Yes
No
(1) In the proposed Attachment 1, Duke Energy believes the criteria for calling an EEA1 should be covered under the BA's Emergency Operating Plan and that additional steps should be taken during EEA1 to prevent the BA from moving into the EEA2, such as calling for conservative operations, curtailment of ALL non-firm use of capacity resources except that retained as Contingency Reserve, and contacting the RC and impacted BAs/TOPs identified under the plan. In addition, we believe that taking some of the actions from EEA2 and moving them to EEA3 will make things more confusing for a System Operator to make the determination of what EEA level the entity is in. The proposed Attachment 1 places some of the actions taken under the currently effective EEA2 and just moves

them to the proposed EEA3, muddying the water on how close a BA may actually be to firm load shedding. Duke Energy believes clear separation should be maintained between the step of utilizing Contingency Reserves to meet firm load requirements, and the step where firm load shedding is imminent or in progress. Our interpretation is that utilizing your Contingency Reserve to meet firm load requirements is part of EEA2 and the shedding of firm load is part of EEA3 respectively. For example, a Balancing Authority (BA) that is maintaining 1000 MW of Contingency Reserves, along with having other measures it's capable of implementing upon use of such reserves (Emergency purchases, public appeals, voluntary load reductions of firm Commercial and Industrial customers,..), may be able to stay within the boundaries of an EEA2 and still maintain balance under BAL-001 without moving to EEA3. (2) Under the proposed Attachment 1, we believe that the required Operating Reserves should be changed to reference required Contingency Reserve, and as implemented to serve firm load, there should not be a requirement to shed load in order to maintain Contingency Reserves. (3) Under the NERC Functional Model, the Load Serving Entity (LSE) is responsible for managing its resource portfolio for meeting the demand and energy requirements of its End-use Customers. The LSE is responsible for coordinating its current-day, next-day, and seasonal operations with its Host Balancing Authority. To the extent that the LSE projects that it will be deficient in meeting its load requirements, the LSE is the entity responsible for working with Purchasing-Selling Entities to procure sufficient resources to address any deficiency. Among other activities under energy emergencies, the LSE communicates requests for voluntary load curtailment to its customers. At a minimum, Duke Energy believes that EOP-011 should retain the capability for the LSE to request the RC to call an EEA. Though EOP-011 and Attachment 1 may not have to be prescriptive in the activities expected of LSEs during an energy emergency, we believe that the responsibility of LSEs to procure additional resources as needed to address real-time deficiencies needs to be clearly understood and not be inadvertently moved to the Host BA by the changes proposed. (4) Based on our comments above, we suggest the following EEA levels for consideration: 1. EEA1 - All available resources in use to serve firm load, firm transactions, and required reserves. 2. EEA2 - Utilization of Contingency Reserves and emergency assistance. 3. EEA3 - Firm Load interruption is imminent or in progress. Further explanation is provided in our response to Question 7.
Yes
Energy Emergency Definition: Duke Energy suggests adding "or Balancing Responsibilities" at the end of the definition. As currently written, the definition suggests that a Balancing Authority carries Load Obligations which is not accurate. A Load Serving Entity does indeed have Load Obligations, but a Balancing Authority does not, and is only responsible for Balancing in its BA Area. Our suggested revision is as follows: Energy Emergency: A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its respective Load Obligations or Balancing responsibilities. R1 and R2 should not have "Reliability Coordinator-approved" included in the requirement. (Please see comments associated with Question 3.) Below are Duke Energy's suggested revisions to Attachment 1: Attachment 1 EOP-002-3.1/ EOP-011-1 modifications Energy Emergency Alerts Introduction This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator (RC) to communicate the condition of a Balancing Authority (BA), which is experiencing an Energy Emergency. A. General Requirements 1. Initiation by Reliability Coordinator. An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of a BA or LSE. 2. Notification. A Reliability Coordinator who declares an Energy Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The RC shall notify the other RCs via RCIS, and the BAs and TOPs in its Reliability Area of any change in EEA level. B. Energy Emergency Alert Levels Introduction To ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established four levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining Energy Emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts. The Reliability Coordinator may declare whatever alert level is necessary, and need not

proceed through the alerts sequentially. 4. EEA 1— All available resources in use to serve firm load, firm transactions, and required reserves. Circumstances: The Requesting BA is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves. During EEA 1, the Requesting BA has the following responsibilities to mitigate the energy emergency progressing to an EEA 2: • Implement its Emergency Operating Plan • Curtail non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) as needed to balance resources and demand. • Curtail non-firm end-use loads including Demand Side Management within the BA Area in accordance with applicable contracts (other than those designated to be shed to meet reserve requirements) as needed to balance resources and demand. • Implement conservative operations protocols within its BA Area to reduce risk of errors impacting resource availability. 5. EEA 2 — Utilization of Contingency Reserves and emergency assistance. Circumstances: The Requesting BA is no longer able to balance its resources and the demand of firm loads and firm transactions without utilization of its Contingency Reserves. During EEA 2, the Requesting BA has the following responsibilities to mitigate the energy emergency progressing to an EEA 3: • Complete EEA 1 actions. • Curtail remaining non-firm wholesale energy sales. • Curtail remaining non-firm end-use loads including Demand Side Management within the BA Area in accordance with applicable contracts. • Implement use of Contingency Reserves to meet firm load obligations • Implement emergency energy purchase transactions. • Issue public appeals to reduce demand • Request voltage reduction • Prepare to shed firm load 2.2 Declaration period. The Requesting BA shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. During EEA 2, the RC has the following responsibilities to mitigate the energy emergency progressing to an EEA 3: 2.3 Evaluating and mitigating Transmission limitations. The RC shall review Transmission outages and work with the TOP to see if it’s possible to return the Transmission Element that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs). 3. EEA 3 - Firm Load interruption is imminent or in progress. Circumstances: The Requesting BA is, or projects that it will, no longer able to balance its resources and the demand of firm loads and firm transactions, and foresees a need for possible interruption of firm Load and firm transactions. During EEA 3, the RC and Requesting BA have the following responsibilities: 3.1 Continue actions from EEA 2. The Reliability Coordinators and the Requesting BA shall continue to take all actions initiated during the EEA 2. 3.2 Declaration Period. The Requesting BA shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. 3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the Requesting BA. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists or as allowed by the Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised: 3.4. Requesting BA obligations. The Requesting BA must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding. 3.5 Returning to pre-emergency conditions. Whenever energy is made available to a Requesting BA such that the transmission systems can be returned to their pre-emergency SOLs or IROLs condition, the Requesting BA shall request the Reliability Coordinator to downgrade the alert level. Alert 0 - Termination. When the Requesting BA is able to maintain its required reserves and balance its resources and demand, it shall request its RC to terminate the EEA.
Individual
Matthew Beilfuss
Wisconsin Electric
No
The term “Operator-controlled” with respect to load shedding is not adequately defined. Control could be interpreted to be via EMS/SCADA functionality or by dispatch of personnel executing switching.
Yes

No
The standard as written does not sufficiently identify the criteria by which the RC would evaluate BA / TOP Emergency Operating Plans. The standard should include criteria similar to EOP-006, R5.1, potential language: The Reliability Coordinator shall determine whether the Emergency Operating Plan is coordinated and compatible with other Emergency Operating Plans within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with stated reasons, the submitted emergency plan within 30 calendar days following the receipt of the plan from the BA/TOP.
Yes
Yes
Yes
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
Southern Company Operations Compliance
Yes
Yes
No
Southern understands the SDT's attempt to address the FERC directive from Order No. 693 to include the reliability coordinator as a necessary entity. Our concern, however, is the operational expectations (and potential compliance implications) of the wording as it stands using the word "approve" and the lack of guidance on what basis approval would be given. Southern agrees with FERC, as acknowledged in its Order for EOP-006, that approval of these plans does not guarantee that they will adequately mitigate an Emergency for a BA/TOP but merely that the plans are compatible and support reliability. Reviewing the various definitions of "approve" indicates it means to "judge favorably or good". Without indicating the context upon which to "judge goodness" one might infer that it includes opportunity for operational success. Due to the details unique to each BA and TOP, only those entities are in a position to judge goodness with regard to operational success. The RC is not in a position to judge such details. The RC role should be limited to reviewing against a specific set of criteria. The RC could participate, as FERC expects, by reviewing the plans and notifying the submitting BA/TOP of issues in their plan based on incompatibility with neighboring BA/TOP emergency operating plans, the potential to create risk to wide area reliability, and incompatibility with RC distributed emergency operating plans. "Approval" and any associated implications on potential success would be avoided. Suggested alternate wording for R3 might be: Each Reliability Coordinator shall review Emergency Operating Plans submitted by Transmission Operators and Balancing Authorities in its RC Area on the basis of a plan element's incompatibility with and non-reciprocal inter-dependency on neighboring BA/TOP emergency operating plans, the potential to create additional risk to wide-area reliability, and incompatibility with RC distributed emergency operating plans and then, within 30 calendar days of submittal, notify the submitting Transmission Operators and Balancing Authorities of any incompatibilities and/or reliability risks identified in the submittal. In addition, the SDT should include a companion requirement for BAs/TOPs to address any incompatibilities and/or reliability risks identified by their RC within a defined time period after being notified of such incompatibilities / reliability risks and certainly prior to the effective date of the Emergency Operating Plans.
Yes

Yes
Yes
R1: We appreciate the SDT's clarification of the term Emergency Operating Plan. The NERC Glossary defines Emergency as, "Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System." Southern continues to believe that the definition of Emergency as applied in EOP-011-1 is too broad. An emergency is considered as an operating condition which has not been studied and for which no mitigating plan has previously been developed. For example, having a contingency occur which was studied and for which a post-contingency mitigation plan has been developed, communicated, and can be implemented prior to an SOL exceedance is not an emergency even though it may require immediate manual action by an operator. Similarly, an IROL which can be mitigated prior to Tv as required by IRO-009 should not be considered an Emergency regardless of what actions the IRO-009-1, R1's Operating Process/Procedure/Plan requires. An Emergency Operating Plan, particularly as it relates to transmission and the TOP should be limited to multi-element contingencies due to things like weather, differential relay operations, relay failures, etc. or to other unstudied states where a potential or actual SOL exceedance needs to be managed as quickly as possible. In addition, Southern recognizes that R1 Rationale states that the Transmission Operator can note R1 Parts are "not applicable" in their plan. However, Southern requests that the SDT add that verbiage in the requirement (R1) rather than relying on rationale boxes that are deleted in final versions of the standards or other supporting documents: "Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, if applicable, the Emergency Operating Plan shall include the following elements:" Southern requests more guidance on the elements listed in R1.2. Are the strategies listed unique to emergency operations? For example, is the Voltage control listed that which is unique to an emergency or also a part of normal voltage control procedures? If these strategies are unique to an emergency, Southern suggests that the SDT add more clarity by removing the sub-bullets and revising the requirement to state: "R1.2. Strategies that are not included in normal operating procedures that are used to prepare for and mitigate Emergencies; " R1.2.6. Southern believes this requirement needs additional clarity by removing coordinated as revised: "Operator-controlled manual Load shedding plan designed to minimize the use of loads that are a part of automatic Load shedding plans;" R2: Southern also believes "if applicable" should be included in the Balancing Authority's Capacity and Energy Emergency Plans as stated in the draft RSAW. If this designation is significant enough to include in the RSAW then it should be stated in the requirement. (see similar comment for R1 above) R2.3 Southern suggests modifying this requirement to be consistent with R5 and Attachment 1 language where a BA requests their RC to initiate an EEA rather than the BA declare an EEA. Southern suggests the following revision: " Criteria to request an Energy Emergency Alert, per Attachment 1;" R2.4.1 Southern suggests adding "if applicable" to this requirement because a BA may not be the sole function that has knowledge of all information listed in the sub-bullets for R2.4.1. R2.4.2, R2.4.3, R2.4.4: Southern requests the SDT to provide guidance on each of these strategies. Are these specific to certain regions or customers and not continent wide? For example, what is the difference between a Voluntary Load reduction and a Public Appeal? Southern requests the SDT to provide examples. R4: Southern would like to see more guidance on determining what "impacted" means since it can be a subjective term and therefore makes the requirement less measureable. In R4, Att. 1 section 2.3, Att. 1 section 3.3, Att. 1 section 3.5.1, and Att. 1 section 0.1, the wording inappropriately intertwines notification/communication from an RC to BAs and TOPs in a manner contrary to current, and in fact very reliable, practices used today . In these locations, the terminology "other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators" or similar words are used. In practice, based on the established hierarchy of RCs and their associated BAs/TOPs, an RC will notify and communicate with other RC's and with the BAs and TOPs in it RC Area. To require an RC to notify/communicate with a non-associated "impacted" BA/TOP as the current draft's wording implies has the potential to cause confusion and is not a relationship which operators are accustom to. BAs/TOPs should be expected to communicate with one and only one RC to maintain the "command and control" hierarchy that is currently used and, in

our opinion, is expected by FERC. We suggest alternate wording for “other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators” or similar references to clearly maintain the established RC to BA/TOP communication hierarchy: An RC will notify “impacted Balancing Authorities and Transmission Operators in their own RC Area as well as other impacted Reliability Coordinators who are expected to notify impacted Balancing Authorities and Transmission Operators in their RC Area” Attachment 1 Section 2.3 - Southern suggests the following revision to limit the scope of BA responsibilities to contact requesting BAs and to clarify the appropriate communications channels : “ A neighboring BA with available resources and that has contractural agreements in place with a requesting BA shall coordinate with it’s RC as appropriate to provide assistance to the requesting BA.” Attachment 1 Section 2.5 Southern suggests that the title “BA actions” be updated to reflect “Requesting BA actions” to reference the appropriate BA. Southern also suggests that the word choice be updated to reflect that a BA can not declare an EEA as indicated the Initiation Section of Attachment 1 and EOP-011-1 R5. Attachment 1 Section 2.5.2 – Southern asks the SDT to consider replacing “curtailed” with “activated” to improve word choice and add clarity. The use of “curtailed” when referring to DSM can be very confusing. Attachment 1 Section 3.2 – Southern requests for the SDT to consider modifying this language because some BAs may not participate in an Operating Reserve sharing program, and to explicity state that it is not required to shed Load to maintain normal Operating Reserves during this abnormal situation. Southern believes that the following revision should be made to add guidance: “Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through an Operating Reserve sharing program, if applicable. In this situation, the requesting BA must be able to, but not required to pre-contingency, shed an amount of firm Load in order to meet its Operating Reserve requirement. A BA may continue to carry reserves below the required minimum and plan to shed Load post contingency.
Group
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana
Erica Esche
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana
Yes
Yes
Yes
Yes
Yes
No
The language in the proposed VSLs for R4 is unclear: High VSL The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority and did notify other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators, but did not do so as soon as practical. Severe VSL The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority and failed to notify, as soon as practical, other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators. We propose that the Severe VSL be revised to remove “as soon as practical”. This will clarify the difference between the High VSL and Severe VSL.
Vectren appreciates the work of the standards drafting team, and generally supports the standard.
Group
ACES Standards Collaborators
Ben Engelby
ACES

No
(1) We do not agree with the approach of combining glossary terms with everyday language. The term “Operator-Controlled” should be a complete defined term “Operator-Controlled Manual Load Shedding.” The approach to combine capitalized terms and lowercase terms only leads to confusion. (2) This is also the case with the combination of two separate defined terms “Emergency Operating Plan.” It is confusing for the drafting team to combine two independent glossary terms (“Emergency” and “Operating Plan”) and expect everyone to understand the meaning of the combined terms. We strongly recommend that the drafting reconsider its approach on introducing separate defined terms. It is unreasonable to expect consistent interpretations with this approach. (3) There is a similar issue with the use of Capacity and Energy Emergencies. The defined terms are Capacity Emergency and Energy Emergency but by putting the “and” between the two, it looks Capacity is a defined term. (4) In regard to the “Emergency Operating Plan,” does this apply to “Energy Emergencies” or “Capacity Emergencies,” or just “Emergencies”? Wouldn’t it be easier for the requirement to drop the word “Emergency” and require an “Operating Plan” instead? The definition of an Operating Plan includes an example of restoration activities, which is very close to what the drafting team is trying to convey. There is not a benefit for combining the terms, as a single term would suffice. (5) If an entity is registered as both a BA and a TOP, would they need two operating plans to address the differences in R1 and R2? If so, we recommend revising these requirements to eliminate duplicative efforts for compliance purposes.
No
We question the rationale of removing Requirement R3. Coordinating emergency operations in an RC Area is ultimately responsibility of the RC. We do not understand the rationale of transferring the responsibility to the TOPs and BAs in an RC Area. Our concern with this approach is the potential scrutiny from an auditor that the registered entity did not coordinate with all “impacted” BAs and TOPs. The requirement is vague as currently written. It’s theoretically possible that a BA or TOP in each interconnection would need to coordinate with every other BA or TOP in the same interconnection for emergency operations. As written, auditors could scrutinize the list of coordinating BAs and TOPs and state that there was not enough coordination for emergency operations. Is this the intent of coordination from the drafting team? If so, then we disagree with the approach and request the drafting team clearly define the scope of coordination.
No
As stated above, the RC should be the responsible entity to coordinate emergency operations in its area. The drafting team needs to consider requiring the RC to coordinate emergency operations with the applicable TOPs and BAs in its RC Area.
Yes
We agree that redundant requirements should be removed. We also believe that combined glossary terms that lead to confusion and administrative tasks without reliability benefits should be removed.
No
We are not supportive of shedding load to preserve Operating Reserves for an EEA 3 as presently included in Attachment 1, Section 3.2 of the standard.
No
The VSL for R4 is ambiguous. How is an auditor or enforcement staff going to measure “as soon as practical?” This is a subjective measure and needs to be revised. One suggestion for improvement would be “without further delay.”
(1) For Requirement R1, we recommend removing “strategies to prepare for” from parts 1.2 and 1.3. The elements of the Operating Plan should be processes or procedures to respond to an Emergency. As written, the Operating Plan will need to have both a strategy and a mitigation activity for each of the elements. How does one have a strategy and a mitigation activity for notifying the RC? Wouldn’t that element be a process step? Parts 1.2 and 1.3 of this requirement need to be modified. (2) For Requirement R2, we recommend removing “strategies to prepare for” from parts 2.2 and 2.3. The elements of the Operating Plan should be processes or procedures to respond to an Emergency. As written, the Operating Plan will need to have both a strategy and a mitigation activity for each of the elements. How does one have a strategy and a mitigation activity for notifying the RC? Wouldn’t that element be a process step? Parts 2.2 and 2.3 of this requirement need to be modified. (3) For Requirement R4, we see no difference between the terms “as soon as practicable” and “as soon as practical.” We strongly recommend revising this requirement with a reasonable

measure of compliance. Also, as stated above, the VSL needs to be reworked, as the subjective measure of not notifying a BA or TOP as soon as practical results in a High violation severity level. This phrase is not appropriate for a reliability standard because it is ambiguous. (4) The term of “Operator-controlled manual Load shedding” should be a defined term. The word “operator” is not a defined term, although it could be assumed to refer to System Operators. There needs to be additional clarification on the intent of the drafting team. (5) There are still incomplete items on this project. The guidelines and technical basis should be included prior to ballot, not “to be added here after balloting.” Without guidelines and technical basis for the drafting team’s decisions, we cannot completely evaluate the standard, and therefore believe that more work is needed to improve the current draft. (6) Thank you for the opportunity to comment.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery
Associated Electric Cooperative, Inc. - NCR01177
Yes
Yes
FOR EOP-011-1 R1 PART 1.3 AND R2 PART 2.5: REPLACE: “with impacted Balancing Autorities and Transmission Operators” WITH: “with Balancing Authorities and Transmission Operators known to be impacted by those plans.” RATIONALE: Compliance concerns with the current wording will likely drive email blasts to neighboring TOPs and BAs, and possibly all within the same Interconnection, thereby creating a volume of insignificant notifications such that notifications containing significant impacts are more likely be overlooked and BES reliability diminished.
Yes
AECI agrees that this requirement provides opportunity for reduced risk to reliability, but disagrees with the assertion that it necessarily reduces risk.
Yes
No
See SERC OC Review Group comment
Yes
AECI Supports SERC OC Review Comments comments for Item 7, and provides the following additional comments for SDT consideration: FOR EOP-011-1: CONSIDER: AECI recommends that future EOP-011-1 postings conform with other NERC draft standard postings that position each requirement’s rationale box immediately preceding the corresponding requirement. RATIONALE: Not only does this help reviewers to check Measures against corresponding Requirements, it appears to be more consistent with NERC SDT’s normative practice. FOR EOP-011-1 R2 PARTS 2.4.2…2.4.8: CONSIDER subjugating parts 2.4.2 through 2.4.8, as parts 2.4.2.1 through 2.4.2.7, beneath a general 2.4.2 topic of “Load reduction resources” (AECI is not wed to this title). RATIONALE: a) Helps to clarify the nature of Public appeals”, unless the SDT is expecting that future public appeals might include their voluntarily adding energy resources for the grid, and b) because part 2.4.9 is substantively different from the preceding topics of Generating resources and Load reduction resources. FOR EOP-011-1 ATTACHMENT 1 PART 3.4: REPLACE: “of the TOP whose equipment” WITH: “of the TOP whose TO equipment” AND REPLACE: “by the TOP whose equipment” WITH: “by the TO whose equipment” RATIONALE: TOs actually own the equipment at risk, but TOPs would typically serve as the middle-man in these conversations, although they may at times have pre-determined formulas provided by the TO. Either way, this suggested language should work.
Individual
David Jendras
Ameren
Yes

No
We believe that the RC should take responsibility for the coordination, at least at the transmission level. Below the transmission level it could be the BA and TOP.
No
We believe that because the majority of manual load shedding is likely to be at sub-transmission voltage levels the RC will not have awareness of this load shedding and will need to rely on the TOP or BA for the specific details.
Yes
No
We believe that operating reserves should stay in EEA 2 until the conflict with operating reserves in BAL-002 is resolved.
No
We believe that R1 should be Medium.
From our understanding there seems to be no mandated timeframe for what constitutes maintenance of TOP or BA emergency plans with respect to load shedding. We ask the drafting team; once the plan is approved by the RC, does the TOP or BA need to review or submit a plan every year, once every three years, or never?
Individual
Cheryl Moseley
Electric Reliability of Texas, Inc.
No
See response C. under Q7 below.
A. Load shedding to restore OR ERCOT does not support the paragraph 3.2 in Attachment 1 as currently drafted. There may be potential value in executing firm load shedding during periods when a region's reserve levels have been compromised. However, the decision to take this operating action should rest solely with the system operator for the region based on its regional rules and real-time operational information. (SHOULD THIS BE THE BA, THE RC OR BOTH? – DO WE WANT TO COMMENT ON THE APPROPRIATE FUNCTIONAL ENTITY TO TAKE THIS ACTION?). Accordingly, ERCOT suggests that the relevant language be deleted from Attachment 1. Appropriate revisions are proposed below. Alternative Proposed Language - delete the relevant language altogether and leave it to the regions to decide whether and how to utilize firm load shedding in the maintenance of system reliability. 3.2 Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. It is likely that different regions will have different approaches to potential firm load shedding during emergency operations. Accordingly, the most effective way to address the issue in Attachment 1, paragraph 3.2, is to delete the language, thereby effectively allowing regions to manage the use of firm load shedding during emergency operations based on their regional rules, as reflected in their EOPs. B. Requirements based on "potential" or "imminent" operating conditions R5 and Attachment 1 EEA 3 section impose obligations based on "potential" and "imminent" operating conditions. These conditions are not defined based on any objective metrics, but rather apparently are triggered based solely on the subjective assessments of the relevant functional entity. This is potentially problematic from a compliance and practical perspective. Because these triggering conditions for action under the relevant section of the standard are ambiguous, this will be problematic in CMEP activities because the auditor and registered entity may have different opinions as to what "potential" and "imminent" conditions are. Accordingly, based on its opinion of what constitutes "potential" or "imminent", the auditor may believe the registered entity should have acted under the relevant section of the standard, whereas based on its opinion, the registered may not have taken the relevant action

because it did not believe the relevant conditions existed. This has the potential to create significant problems during CMEP reviews. From a practical perspective, to mitigate the potential for related compliance issues, the registered entity may be motivated to take conservative action under the standard to avoid violations. In other words, the entity may determine the "potential" or "imminent" condition exists, thereby tirggering the relevant operating action (e.g. initiating EEA under R5) when conditions do not warrant such action. This potential scenario and the associated problems are exacerbated by the fact that system conditions are dynamic and such conservative behavior will be triggered by different operating conditions all the time so there will be no definition or transparency as to what constitutes "potential" or "imminent" conditions. This is not only problematic from an operational perspective, but also from a markets perspective, because market participants will have no clear understanding of what triggers the relevant emergency actions w/r/t "potential" or "imminent" conditions. Conversely, the objective actual EEA thresholds do establish known, transparent system conditions that trigger the relevant emergency operational actions. Furthermore, those thresholds were developed to define emergency conditions and distinguish them from normal operations. Accordingly, there is no need to create ambiguous and vague emergency condition triggers based on "potential" and "imminent' conditions. The NERC rules should allow normal/market rules to support system operations until such time as the objective, specifically defined emergency conditions arise, which should be the trigger for the relevant emergency operations. C. RC approval of the TOP and BA emergency plans The proposed standard requires TOPs and BAs to have RC approved emergency plans, and, accordingly, requires the RC to approve/disapprove the relevant entities' plans. ERCOT does not support the RC approval requirement. The relevant FERC directives (PP 547 and 548 in Order 693) do not require this. FERC stated that the RC should be an applicable entity under the standard, finding that "...the Commission is persuaded that specific responsibilities for the reliability coordinator in the development and coordination of emergency plans must be included as part of this Reliability Standard." (emphasis supplied). Thus, the Commission explicitly found that the role of the RC is to facilitate coordination in the development of other entities' plans. Thus, the proposed standard's RC approval requirement is not required by Order 693 and isn't necessary or appropriate. The RC should review and comment on the emergency plans of TOPs and BAs in their regions to foster coordinated, efficient and effective emergency operations, but they should not have approval authority. Imposing an approval requirement inappropriately inserts third party involvment in the actionable obligations of another entity, which raises practical as well as compliance issues. Accordingly, the RC approval requirement should be changed to a review and comment RC action. Requirements R1.2.1 - Including the obligation to include system conditions in the notification is inappropriate. "System" is defined in terms of generation, transmission and distribution. How is the LSE or BA going to know system conditions, which, by definition includes transmission and distribution. And if it's an LSE, how will they know generation conditions? The notice should just be to inform the RC that it is in an Operating emergency. R1.2.3 - Rather than saying cancellation or recall, why not just say "Management of Transmission and generation outages"? Cancellation / recall seems too prescriptive and implies full cancellation or recall of an outage. Couldn't there be other options - e.g. partial recall? R2.4.1 - The items listed are not emergencies, which is how it reads. Rather they are considerations in mitigating emergencies. R2.4.4 - This implies that the BA has to research and be aware of all such programs. What if a program is missed or the BA is not aware of one? Why can't this be captured under public appeals? Also, what is a "necessary" energy reduction? Is it relative to the emergency shortfall or the number in the government program? 2.4.5 - What is reduction of internal utility energy use? Is it referring to energy reduction of the BA? if it is relative to third parties it is inappropriate. Even if it is relative to the BA at issue it is not appropriate. The plan should be related to external operational considerations. This should not be dictating internal entity business practices. 2.5 – Replace “Strategies” with “Policies” for coordinating EOPs. R4 - Should be revised to say "as soon as practical as determined by the RC" to make it measurable. The intent of the revision is to mitigate the ambiguity associated with the general "as soon as practical" timing requirement for the notice by defining it explicitly in terms of the RC determination to issue the notice when it is feasible/practical. This mitigates the potential for different subjective opinions on what this means between the CEA and registered entity in the context of CMEP activities. Attachment 1 - Section B - Introduction – Delete the first part of the first sentence. It should just say there are four EEA levels. Also, the last sentence is unnecessary and confusing. EEA is an operating practice, just limited to emergencies. Delete the entire sentence. EEA 1 - Delete "and is concerned about sustaining its required Operating

Reserves." This is ambiguous and creates potential audit problems. Make the trigger relative to an objective metric, which is achieved by the first part - i.e. all generation is committed.
Individual
Marc Donaldson
Tacoma Power
Yes
Yes
Yes
Yes
No
Attachment 1, EEA's 2 and 3 have been revised with respect to use of Operating Reserves. The Operating Reserve criteria have been removed from EEA 2, under EEA 3 is the following new requirement: 3.2 Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement. It is unclear how this situation may or may not be applied to entities whom are a member of a reserve sharing group. While I believe I understand the intent of this requirement, it may lead to confusion or potential application of this requirement where it should not be applicable. I feel that further revisions are necessary to address Reserve Sharing Groups.
Yes
R2.3 needs to be revised to state "Criteria to request declaration of an Energy Emergency Alert per Attachment 1"
Group
ISO/RTO Cojuncil Standards Review Committee
Greg Campoli
NYISO
Yes
Yes
No
We are concerned with the lack of detail in the R3 requirement for the RC to approve the EOPs of the TOPs and BA. R3 should include a requirement for the BA and TOP to submit their proposed EOPs to the RC. Also, the lack of detail and criteria for approval in R3 could lead to a misinterpretation that RC approval involves checking compliance. We would like to suggest the following alternative language, which is along the lines of what is currently contained in EOP-005-2 and EOP-006-2: R3. Each Transmission Operator and Balancing Authority shall submit its proposed Emergency Operating Plan and any subsequent proposed changes to its Emergency Operating Plan to its Reliability Coordinator. 3.1 The Reliability Coordinator shall review each proposed Emergency Operating Plan it receives from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area and determine whether the Emergency Operating Plan is coordinated and compatible with the Reliability Coordinator's Emergency Operating Plan and shall approve or disapprove, with stated reasons for disapproval, the Emergency Operating Plan within 30 calendar days following the receipt of the Emergency Operating Plan from the Transmission Operator or Balancing Authority. Alternative, 3.1 can be stated as a separate requirement to avoid the confusion of having multiple entities in one requirements having different mandates. Note that ERCOT does not support this comment.

Yes
No
We are concerned with the added sentence that “In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement.” We do not agree that the deficient BA needs to shed firm load to meet the OR requirement. For so long as OR is still available, albeit depleted, a BA should be able to continue to utilize its OR to meet resource/demand/interchange balance. We do not support the idea of shedding firm load to avoid having to shed firm load when a resource contingency occurs or before the OR is fully utilized. Note that ERCOT does not support this comment.
No
A. The condition “did not do so as soon as practical” in the HIGH VSL for R4 cannot be determined with any certainty or supported evidence. R4 itself need to be revised to provide the measurability to support compliance assessment. Please see our comment under Q7. B. We suggest lowering the VSL for R5 from Medium to Low since failure to notify others that the alert has ended does not result in any unreliable operations.
A. We do not agree with the proposed revision to the definition for Energy Emergency. The phrase “has exhausted all other resource options” is unnecessary but begs the question on what are these other options. Further, since LSE is no longer referenced in any of the requirements and hence energy emergency conditions are now generally linked to a BA, the reference to LSE should also be removed. We therefore suggest the definition be revised to: Energy Emergency - A condition when a Balancing Authority can no longer meet its expected demand/resource/interchange obligations. B. Requirement R1: We propose the following revision to avoid ambiguity and to add clarity: 1.1 Simply change it to Emergency Operating Plan roles and responsibilities since “activate and implement” are provided in the emergency operating plan itself. 1.2 Replace “strategies” with “procedures” as the latter is more specific and can better facilitate compliance assessment 1.2.7 We do not see the need to specify “extreme weather conditions”. The TOP needs to mitigate adverse reliability impacts caused by any reasons – parallel flows, heaving loading caused by demand exceeding forecast, transmission facility forced outages, etc., not just extreme weather conditions. Suggest to remove 1.2.7 since this is already covered by the other parts. 1.3 Suggest replacing “strategies” with “process” as the latter is more specific and can better facilitate compliance assessment C. Requirement R2: We propose the following revision to avoid ambiguity and to add clarity: 2.1 Simply change it to “Emergency Operating Plan roles and responsibilities” since “activate and implement” are provided in the emergency operating plan itself. 2.4 Replace “strategies” with “procedures” as the latter is more specific and can better facilitate compliance assessment, and add the phrase “the following measures” to clarify that Parts 2.4.1 to 2.4.9 are the possible mitigating measures; and delete Part 2.4.9 since this is already covered by the other parts. 2.5 Suggest replacing “strategies” with “process” as the latter is more specific and can better facilitate compliance assessment D. Requirement R4 is not measurable since there is no clear yardstick for “as soon as practical”. While a time period may be subject to different views, we nevertheless suggest the SDT consider revising it to “shall notify, as soon as practical but no later than 5 minutes after receiving the notification unless conditions do not permit such communications,” to put a bound on the time frame to support compliance assessment. Note that ERCOT does not support this comment (above). E. The wholesale replacement of “Energy Deficient Entity” with “Requesting BA” results in some inconsistency with Condition (1) in the General Responsibility A.1 of Attachment 1, which indicates that an RC may initiate an EEA on its own request. Clearly, an RC will likely issue an EEA when it identifies that a BA(s) in its RC Area is anticipating or experiencing an energy deficiency. Nonetheless, the use of “Requesting BA” only in the rest of Attachment 1 fails to address the cases where a BA is energy deficient but it does not request its RC to initiate an EEA; rather, it’s the RC that initiates the EEA before being requested. We suggest that the SDT consider replacing “Requesting BA” with “Energy Deficient BA” or simply reinstate the phrase “Energy Deficient Entity”. We further suggest that “Energy Deficient BA” be defined within Attachment 1 by adding a sentence after the first sentence in the “Introduction” section as follows: “The BA who is experiencing an Energy Emergency is referred to as an “Energy Deficient BA.” EOP-011 R1.2 and R2.4 should include the phrase to ‘include the applicable elements’ and remove the phrase ‘at a minimum’. This would be consistent with the previous language contained in existing EOP-001 R4 and allow for solutions that do not exist or are not ‘applicable’ in certain areas. Also we are wondering about the word ‘impact’ in Part

1.2.7 and 2.4.9. Impact is not a measurable word to aid compliance assessment. F. The term Load-Serving Entity been deleted from R5 and Attachment 1 but it has not been deleted from the definition of “Energy Emergency.” The term also continues to appear in the shaded area right below the definition of “Energy Emergency.” We suggest deleting the term everywhere it appears. G. In the Purpose, R1, and 1.2.1, the word “operating” that appears before “Emergency” or “Emergencies” should be deleted, as it unnecessary. Same comment applies to VSLs for R1 (delete “operating” before “Emergencies” and before “Emergency”). H. In 1.2.2, the word “control” should not be capitalized because “Voltage Control” is not a defined term. I. The word “and” should be deleted at the end of 1.2.7, if this part is retained (please see our comment under 7B, above. If the SDT’s goal is to have 1.3 be at the same level as 1.2 then the “and” is not necessary. J. The SDT has indicated in the Rationale for R1 that “Emergency Operating Plan” is not a newly-defined term but that two defined terms (“Emergency” and “Operating Plan”) are being used. Having the two terms used together creates a false assumption or expectation that “Emergency Operating Plan” is a defined term. We therefore suggest to either: Define the term “Emergency Operating Plan as: an Operating Plan that addresses Emergencies.” , or, Revise the standard to replace “Emergency Operating Plan” with “Operating Plan for Emergencies”. K. Compliance 1.1 – It is not necessary to repeat the definition of Compliance Enforcement Authority. A reference to the NERC Rules of Procedure is sufficient. The benefit is that, if the definition ever changes there, it will not have to be changed here. Therefore, 1.1 under Compliance should simply say: “Compliance Enforcement Authority” has the meaning ascribed to it in the NERC Rules of Procedure. L. For greater consistency, we suggest that the term “declare” be used throughout the Standard whenever Energy Emergency Alerts are discussed: (i) R5 – change “shall initiate an Energy Emergency Alert” to “shall declare an Energy Emergency Alert”; (ii) R5 Rationale: change “initiated” to “declared”; (iii) M5: change “initiated” to “declared” (also make corresponding changes in VSL section for R5); (iv) Attachment 1, A.1: change “Initiation by RC. An Energy Emergency Alert (EEA) may be initiated only by a RC” to “Declaration by RC. An Energy Emergency Alert (EEA) may be declared only by a RC.” M. The drafting team should consider removing EOP-011 R4 since it is redundant to the following requirements: - IRO-015-1 R1 requires RC’s to communicate notifications that impact neighboring RC’s - EOP-002-4 R2 requires BA’s to communicate notifications that impact neighboring BA’s - TOP-001-2 R5 requires TOP’s to communicate notifications that impact neighboring TOP’s N. Attachment 1: - A. 1: Replace “RC’s own request” with “RC’s own initiative” - 2. Replace “reliability area” with “the RC Area” - Section B, Introduction: Suggest to remove the last sentence since it is unnecessary and confusing. EEA is an operating practice, just limited to emergencies. - EEA 1, Circumstances: Suggest to remove the last part "and is concerned about sustaining its required Operating Reserves." This part is ambiguous and may create audit problems; it makes trigger relative to an objective metric, which is already achieved by the first part. i.e. all generating resources are already committed. - EEA 2, Circumstances: We suggest delete “Requesting BA has implemented its approved Emergency Operations Plan.” since declaring EEA (which has 4 levels) is part of the BA’s Emergency Operating Plan per Requirement R2, which it is still implementing but not yet completed. - EEA 2, Section 2.4: Suggest to revise “return the Transmission element that may relieve” to “return any transmission elements that may relieve”. - EEA 2 – Section 2.5: Suggest to revise the first sentence to “Before an EEA 3 is declared, the requesting BA….” - EEA 2, Section 2.5.1: The added language of "not being held for contingency reserves" is confusing (e.g. does it qualify peaking units, peaking and quick start or all gen) and does not appear to be needed. The sentence states that it only applies to generation that is "capable" of being on line. This implicitly excludes gen being held back for some other reason. Therefore, we suggest removing that last part “not being held for contingency reserves”. - EEA 3, Section2.5.2: Suggest to delete "within provisions of any applicable agreements", which is potentially restricting and confusing because not all DSM is via agreements. It should simply states “Initiate all relevant DSM that is capable of being dispatched/utilized.” Also, for reasons noted above, delete "not being held for contingency reserves". - EEA 3, Section 3.4: Should the TOP be TO, whose facility could be affected by the SOL/IROL reevaluation? - EEA 3, Section 3.4.1: This Section does not seem to be required since a BA is obligated to follow an RC’s directive anyway. - EEA 3, Section 3.5.1: Suggest to clarify the role and sequence by replacing “that an alert has been downgraded” with “to downgrade the alert”.
Group
PacifiCorp
Sandra Shaffer

PacifiCorp
No
PacifiCorp generally supports the added term “Operator-Controlled” preceding “manual Load shedding” in parts of Requirements R1 and R2. Added clarity for R1 and R2 would be provided by including portions of the Rationale section in the Requirement. Therefore, PacifiCorp recommends the Standard Drafting Team include a stand alone subrequirement in R1 and R2 pertaining to Load shedding, which reads as follows: “For Load shedding plans, automatic Load shedding schemes are an important backstop against cascading outages or system collapse. If an entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. The Emergency Operating Plan shall include Operator-Controlled manual Load shedding plan(s) coordinated to minimize the use of automatic Load shedding.”
Yes
Yes
Yes
No
PacifiCorp disagrees with removing “Operating Reserves” from EEA 2 and adding it to EEA 3. For background, it is our understanding that when the Reliability Coordinator is communicating Energy Emergency Alerts (EEA) to Balancing Authorities, there is an orderly progression in resource deficiency for EEA 1, 2, and 3: Level 1 is characterized as all resources being in service, yet reserve requirements are continuing to be met; Level 2 is characterized by an erosion in the resource/load balance to the point that operating reserves are being impacted; and finally, Level 3 indicates that firm Load may no longer be able to be served. The Standard Drafting Team’s proposal to move the inability to meet “Operating Reserves” characterization of system conditions into EEA 3 affects the orderly progression for EEA 1, EEA 2, and EEA 3. Proposed EEA 2 would involve deploying all resources except for contingency reserves, which would include deployment of Operating Reserves in excess of contingency reserves. However, proposed EEA 3 (supposedly more severe) states that Operating Reserves are maintained instead of deployed. This reverses the level of severity. The purpose of Operating Reserves is to be deployed to serve expected or unexpected swings in Load. When those swings occur, PacifiCorp deploys the Operating Reserves, up to the full amount available if necessary. The language in Attachment 1, Section 3.2 states that instead of deploying Operating Reserves to serve Load, entities would shed Load to serve our Operating Reserves. We find this unacceptable.
PacifiCorp recommends the Standard Drafting Team replace the word ”Strategies” with ”A process” in R1.3 and R2.5 for coordinating Emergency Operating Plans with impacted Balancing Areas and Transmission Operators. PacifiCorp believes a process for Plan coordination, combined with evidence such as communication documentation, would provide improved compliance evidence, based on the Measures described in M1 and M2.
Group
Bonneville Power Administration
Jamison Dye
Transmission Reliability Standards Group
Yes
Yes
Yes
Yes

Yes
Yes
Individual
Joshua Andersen
Salt River Project
Yes
Yes
No
We do not agree that the RC approval is necessary to enhance reliability. The additional administrative burden for all of the applicable entities, including the RC, does not provide a significant enhancement to reliability. This burden includes evidence of submittal of the Plan to the RC, RC review of each plan in its footprint and evidence of RC approval for each entity. This is a significant burden for each entity that doesn't provide an equitable reliability enhancement. The EOP SDT should consider changing the language in requirements R1, R2 & R3 to state that emergency plan coordination with the RC is required, just as it is among BA's and TO's. The language could include a requirement for the RC to review each plan for coordination and effectiveness. We believe that the revised coordination language will satisfy the FERC Order 693 and minimize the administrative evidence burden on the applicable entities.
Yes
Yes
Yes

Additional Comments:

Austin Energy
Thomas Standifur

1. Based on comments from stakeholders, the EOP SDT has added the term "Operator-Controlled" preceding the language "manual Load shedding" in Parts of Requirements R1 and R2. Do you agree with this revision? If not, please provide specific suggestions for change in the comment area.

   ☒ Yes

   ☐ No

   Comments:

2. Based on comments from a majority of stakeholders, the EOP SDT removed Requirement 3 from EOP-011-1 draft 1 and has placed the requirement on the Balancing Authority and Transmission Operator to coordinate their Emergency Operating Plans with impacted

Balancing Authorities and Transmission Operators. Do you agree with this revision? If not, please provide specific suggestions for change in the comment area.

☒ Yes

☐ No

Comments:

3. The EOP SDT received several comments regarding Reliability Coordinator approval of Balancing Authority and Transmission Operator Emergency Operating Plans. The FERC directive in Paragraph 548 or Order 693 mandates that the Reliability Coordinator be included as an applicable entity; while plan approval by the Reliability Coordinator was not a specific mandated intent, the EOP SDT believes that approval by the Reliability Coordinator reduces risk to reliability of the BES. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.

☐ Yes

☒ No

Comments: City of Austin dba Austin Energy (AE) does not believe Reliability Coordinators need to approve individual entity's Emergency Operating Plans. The effort presents an administrative burden on both the RC and the BA/TOP RC. AE believes the benefit of RC involvement could be in the concept of the RC coordination from the wide-area perspective. AE further believes RC coordination should not require RC approval. The RC could receive plans and be required to comment only if it identifies coordination issues. However, the SDT removed that concept (formerly R3) in this draft, and AE supports that decision. With the removal of the coordination role for the RC, AE remains unclear as to the intent of the RC approval. AE respectfully asks the SDT to remove this concept from the proposed versions of EOP-011-1 in consideration of Paragraph 81 criteria regarding administrative burden with no benefit to reliability. Further AE suggests considering the inclusion of the Reliability Coordinator in R4 and R5 as a response to the FERC directive in Paragraph 548 of Order 693.

4. The EOP SDT has removed Requirement R5 from EOP-011-1 draft 1, as it is redundant with currently-enforceable TOP-001-1a. Do you agree with this revision? If not, please explain in the comment area below.

☒ Yes

☐ No

Comments: City of Austin dba Austin Energy (AE) supports the removal of R5 from EOP-011-1 draft 1 due to redundancy with TOP-001-1a. It seems, however, the SDT moved the concept into R1 Part

1.2.1 and R2 Part 2.2 of EOP-011-1 draft 2. AE disagrees with the addition of these parts to R1 and R2 for the same reasons (redundancy) as before.

5. The EOP SDT has revised Attachment 1, removing “Operating Reserves” from EEA 2 and adding “Operating Reserves” into EEA 3. Do you agree with this change? If not, please explain in the comment area below.

☐ Yes

☐ No

Comments: [intentionally left blank]

6. Do you agree with the VRFs and VSLs in EOP-011-1? If not, please indicate which Requirement(s) and specifically what you disagree with, and provide suggestions for improvement.

☒ Yes

☐ No

Comments:

7. If you have any other comments on this Standard that you haven’t already mentioned above, please provide them here:

Comments: (1) City of Austin dba Austin Energy (AE) seeks clarity stating the Emergency Operating Plan required under R1 can be a single document or a combination of documents. This is similar to the allowance for a plan or set of plans in currently enforceable EOP-001-2.1b. (2) AE suggests the SDT remove the phrase “and generation” from R1, Part 1.2.3, as the TOP does not have control over generation outages. (3) AE suggests the SDT remove R1, Part 1.2.5, “Redispatch of generation request.” The TOP does not have the responsibility of generation dispatch nor does it necessarily have the visibility into the system to appropriately request generation redispatch.

Consideration of Comments

Project 2009-03 Emergency Operations

The Project 2009-03 Emergency Operations Drafting Team thanks all commenters who submitted comments on the standard. These standards were posted for a 45-day public comment period from July 2, 2014 through August 15, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 56 sets of comments, including comments from approximately 174 different people from approximately 120 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process. If you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Guy Zito	Northeast Power Coordinating Council										X

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	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
8.	Kathleen Goodman	ISO - New England	NPCC	2
9.	Michael Jones	National Grid	NPCC	1

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

10.	Mark Kenny	Northeast Utilities	NPCC	1
11.	Helen Lainis	Independent Electricity System Operator	NPCC	2
12.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
13.	Bruce Metruck	New York Power Authority	NPCC	6
14.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
15.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
16.	Robert Pellegrini	The United Illuminating Company	NPCC	1
17.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
18.	David Ramkalawan	Ontario Power Generation, Inc,	NPCC	5
19.	Brian Robinson	Utility Services	NPCC	8
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New York Power Authority	NPCC	5
23.	Ben Wu	Orange and Rockland Utilities Inc,	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	John A. Libertz	The FRCC Operating Committee (Member Services)	X									
N/A													
3.	Group	Janet Smith	Arizona Public Service Company	X		X		X	X				
N/A													
4.	Group	Kaleb Brimhall	Colorado Springs Utilities	X		X		X	X				
N/A													
5.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power Company	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

8.	Ken Goldsmith	Alliant Energy	MRO	4
9.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
10.	Marie Knox	MISO	MRO	2
11.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
12.	Randi Nyholm	Minnesota Power	MRO	1, 5
13.	Scott Nickels	Rochester Public Utilities	MRO	4
14.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
15.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
16.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

6.	Group	Richard Hoag	FirstEnergy Corp	X		X	X	X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. William Smith	FirstEnergy Corp	RFC	1
2. Cindy Stewart	FirstEnergy Corp	RFC	3
3. Doug Houlbaugh	Ohio Edison	RFC	4
4. Ken Dresner	FirstENergy Solutions	RFC	5
5. Kevin Querry	FirstEnergy Solutions	RFC	6

7.	Group	Jared Shakespeare	Peak Reliability	X									

N/A

8.	Group	Connie Lowe	Dominion	X				X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Louis Slade		SERC	1, 3, 5, 6
2. Mike Garton		NPCC	5
3. Randi Heise		RFC	5, 6

9.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Allen	City Utilities of Springfield	SPP	1, 4
2.	Kaleb Brimhall	Colorado Springs Utilities	WECC	1, 5, 6
3.	Michelle Corley	Cleco Power	SPP	1, 3, 5, 6
4.	Louis Guidry	Cleco Power	SPP	1, 3, 5, 6
5.	Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5
6.	Robert Hirchak	Cleco Power	SPP	1, 3, 5, 6

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

7.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
8.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
9.	Mike Kidwell	Empire District Electric	SPP	1, 3, 5
10.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
11.	Jeff Knottek	City Utilities of Springfield	SPP	1, 4
12.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
13.	Ron Losh	Southwest Power Pool	SPP	2
14.	Greg McAuley	Oklahoma Gas & Electric	SPP	1, 3, 5
15.	Shannon Mickens	Southwest Power Pool	SPP	2
16.	James Nail	City of Independence, MO	SPP	3, 5
17.	Randy Root	Grand River Dam Authority	SPP	1
18.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5
19.	Bryan Taggart	Westar Energy	SPP	1, 3, 5, 6
20.	Sing Tay	Oklahoma Gas & Electric	SPP	1, 3, 5
21.	Ellen Watkins	Sunflower Electric Power Corporation	SPP	1
22.	J. Scott Williams	City Utilities of Springfield	SPP	1, 4
23.	Bryn Wilson	Oklahoma Gas & Electric	SPP	1, 3, 5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10. Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. DeWayne Scott		SERC	1
2. Ian Grant		SERC	3
3. Brandy Spraker		SERC	5
4. Marjorie Parsons		SERC	6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11. Group	Kathleen Black	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Kent Kujala	NERC Compliance	RFC	3
2. Daniel Herring	NERC Training & Standards Development	RFC	4
3. Mark Stefaniak	Generation Optimization	RFC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	LG&E and KU Energy, LLC	SERC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10

2.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
3.	Annette Bannon	PPL Generation, LLC	RFC	5
4.		PPL Susquehanna, LLC	RFC	5
5.		PPL Montana, LLC	WECC	5
6.	Elizabeth Davis	PPL EnergyPlus	MRO	
7.			NPCC	
8.			RFC	
9.			SERC	
10.			SPP	
11.			WECC	

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13.	Group	Tom McElhinney	JEA	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ted Hobson		FRCC	1
2.	Garry Baker		FRCC	3
3.	John Babik		FRCC	5

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14.	Group	Stuart Goza	SERC OC Review Group	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Joel Wise	TVA	SERC	1, 3, 5, 6
2.	Connie Lowe	Dominion	SERC	1, 3, 6
3.	Ray Phillips	AMEA	SERC	4
4.	William Berry	OMU	SERC	3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
15.	Group	Paul Haase	Seattle City Light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pawel Krupa	Seattle City Light	WECC	1
2.	Dana Wheelock	Seattle City Light	WECC	3
3.	Hao Li	Seattle City Light	WECC	4
4.	Mike Haynes	Seattle City Light	WECC	5
5.	Dennis Sismaet	Seattle City Light	WECC	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
16.	Group	Carol Chinn	Florida Municipal Power Agency	X			X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

1. Tim Beyrle	City of New Smyrna Beach	FRCC	4
2. Jim Howard	Lakeland Electric	FRCC	3
3. Greg Woessner	Kissimmee Utility Authority	FRCC	3
4. Lynne Mila	City of Clewiston	FRCC	3
5. Cairo Vanegas	Fort Pierce Utilities Authority	FRCC	4
6. Randy Hahn	Ocala Uitlity Services	FRCC	3
7. Stanley Rzad	Keys Energy Services	FRCC	4
8. Don Cuevas	Beaches Energy Services	FRCC	1
9. Mark Schultz	City of Green Cove Springs	FRCC	3
10. Tom Reedy	Florida Municipal Power Pool	FRCC	6
11. Steve Lancaster	Beaches Energy Services	FRCC	3
12. Richard Bachmeier	Gainesville Regional Utilities	FRCC	1
13. Mike Blough	Kissimmee Utility Authority	FRCC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
17. Group	Michael Lowman	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hils			1
2. Lee Schuster			3
3. Dale Goodwine			5
4. Greg Cecil			6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18. Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	X		X		X	X				
N/A												
19. Group	Erica Esche	Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	X		X		X	X				
N/A												
20. Group	Ben Engelby	ACES Standards Collaborators						X				

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

Additional Member		Additional Organization	Region	Segment Selection
1.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1, 5
2.	Scott Brame	North Carolina Electric Membership Corporation	SERC	3, 4, 5
3.	Matthew Caves	Western Farmers Electric Cooperative	SPP	1, 5
4.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
5.	Luis Zargoza	Sunflower Electric Power Corporation	SPP	1
6.	Mark Ringhausen	Old Dominion Electric Cooperative	SERC	3, 4
7.	Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5
8.	John Shaver	Arizona Electric Power Cooperative/Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
9.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1
10.	Steve McElhaney	South Mississippi Electric Power Association	SERC	1, 3, 4, 6
11.	Karl Kohlrus	Prairie Power Inc.	SERC	3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
21. Group	David Dockery	Associated Electric Cooperative, Inc. - JRO00088	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Central Electric Power Cooperative		SERC	1, 3
2. KAMO Electric Cooperative		SERC	1, 3
3. M & A Electric Power Cooperative		SERC	1, 3
4. Northeast Missouri Electric Power Cooperative		SERC	1, 3
5. N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6. Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
22. Group	Greg Campoli	ISO/RTO Cojuncil Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Al DiCaprio	PJM	RFC	2
2.	Cheryl Moseley	ERCOT	ERCOT	2
3.	Kathleen Goodman	ISO-NE	NPCC	2
4.	Ali Miremadi	CAISO	WECC	2
5.	Charles Yeung	SPP	SPP	2
6.	Terry Bilke	MISO	MRO	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7. Ben Li	NPCC	NPCC	2										
23.	Group	Sandra Shaffer	PacifiCorp						X				
N/A													
24.	Group	Jamison Dye	Bonneville Power Administration	X		X		X	X				
Additional Member	**Additional Organization**	**Region**	**Segment Selection**										
1. Chris Sanford	Transmission Dispatch	WECC	1										
2. Chris Higgins	Transmission Dispatch	WECC	1										
3. Fran Halpin	Duty Scheduling	WECC	5										
25.	Individual	Wendy	NERC										
26.	Individual	Julius Horvath	Wind Energy Transmission Texas, LLC	X									
27.	Individual	Len Kula	Independent Electricity System Operator		X								
28.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
29.	Individual	Anthony Jablonski	ReliabilityFirst										X
30.	Individual	John Brockhan	CenterPoint Energy Houston Electric, LLC	X									
31.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
32.	Individual	Michael Haff	Seminole Electric Cooperative, Inc.	X		X	X	X	X				
33.	Individual	Linda Campbell	FRCC										X
34.	Individual	Amy Casuscelli	Xcel Energy	X		X		X	X				
35.	Individual	Russell Noble	Public Utility District No. 1 of Cowlitz County, WA			X	X	X					
36.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X					
37.	Individual	Brett Holland	Kansas City Power & Light	X		X		X	X				
38.	Individual	Kayleigh Wilkerson	Lincoln Electric System	X		X		X	X				
39.	Individual	Denise Lietz	Puget Sound Energy	X		X		X					
40.	Individual	Richard Vine	California ISO		X								
41.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
42.	Individual	Josh Smith	Oncor Electric Delivery LLC	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
43.	Individual	Dave Willis	Idaho Power Co.	X									
44.	Individual	Andrew Pusztai	American Transmission Company LLC	X									
45.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
46.	Individual	Karin Schweitzer	Texas Reliability Entity										X
47.	Individual	Rich Salgo	NV Energy	X		X		X					
48.	Individual	Chris Scanlon	Exelon Companies	X		X		X	X				
49.	Individual	Scott Langston	City of Tallahassee	X									
50.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
51.	Individual	Bob Thomas and Alice Schum	Illinois Municipal Electric Agency				X						
52.	Individual	Matthew Beilfuss	Wisconsin Electric			X	X	X					
53.	Individual	David Jendras	Ameren	X		X		X	X				
54.	Individual	Cheryl Moseley	Electric Reliability of Texas, Inc.		X								
55.	Individual	Marc Donaldson	Tacoma Power	X		X	X	X	X				
56.	Individual	Joshua Andersen	Salt River Project	X		X		X	X				

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration:

Organization	Agree	Supporting Comments of "Entity Name"
FirstEnergy Corp	Agree	FE supports PJM's comments
Tennessee Valley Authority	Agree	SERC OC Review Group
South Carolina Electric and Gas	Agree	SERC OC
Seminole Electric Cooperative, Inc.	Agree	FRCC Operating Committee
Kansas City Power & Light	Agree	SPP - Robert Rhodes
California ISO	Agree	ISO/RTO Standards Review Committee
Hydro-Quebec TransEnergie	Agree	NPCC
City of Tallahassee	Agree	The FRCC Operating Committee (Member Services)
South Carolina Electric and Gas	Agree	SERC OC
Illinois Municipal Electric Agency	Agree	PJM, and SERC OC Review Group
Colorado Springs Utilities		Southwest Power Pool (SPP)
Lincoln Electric System		SPP Standards Review Group

1. **Based on comments from stakeholders, the EOP SDT has added the term "Operator-Controlled" preceding the language "manual Load shedding" in Parts of Requirements R1 and R2. Do you agree with this revision? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration: The Emergency Operations Standard Drafting Team (EOP SDT) appreciates the comments received by industry. Based on the feedback received, the EOP SDT modified Requirements R1.2.6 and R2.4.8. The SDT changed wording to better reflect the intent described in the rationale by stating that the manual Load shedding plan overlap with automatic plans should be minimized. Other comments received requested the SDT to remove the term "Emergency" from "Emergency Operating Plan," the EOP SDT agrees and made that change. Finally, commenters requested that the EOP SDT modify Requirements R1 and R2 to include the terms "not applicable." The EOP SDT modified Requirements R1 and R2 to include "not applicable" within the requirements, where the prior version reflected this intent by the SDT within the rationale box.

Organization	Yes or No	Question 1 Comment
DTE Electric	No	In 1.2.6 and 2.4.8, the "Operator-Controlled" language is acceptable but "coordinated to minimize the use of automatic Load sheding" is vague compared to the intent of the requirement as explained in the Rationale. Since the intent is to reduce the overlap between manual and automatic Load shedding schemes, why not state it clearly in the requirement? Consider changing 1.2.6 and 2.4.8 to "Operator-controlled manual Load shedding plan coordinated to minimize the overlap with automatic Load shedding schemes." EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised requirements.
Duke Energy	No	Duke Energy agrees in concept with R1 and R2, but feel that the language used in R1.2.6 and R2.4.8, should be revised to better reflect what we perceive to be the SDT's intent. We suggest that the language should more closely mirror that which is stated in the accompanying guideline document. We suggest the following revision for R1.2.6, and R2.4.8:"Operator-controlled manual Load shedding plan coordinated to minimize the use of Load shed under automatic Load shedding;" EOP SDT: The SDT appreciates your comments and have modified the requirements that they believe reflects the changes you recommended.

Organization	Yes or No	Question 1 Comment
ACES Standards Collaborators	No	(1) We do not agree with the approach of combining glossary terms with everyday language. The term "Operator-Controlled" should be a complete defined term "Operator-Controlled Manual Load Shedding." The approach to combine capitalized terms and lowercase terms only leads to confusion. (2) This is also the case with the combination of two separate defined terms "Emergency Operating Plan." It is confusing for the drafting team to combine two independent glossary terms ("Emergency" and "Operating Plan") and expect everyone to understand the meaning of the combined terms. We strongly recommend that the drafting reconsider its approach on introducing separate defined terms. It is unreasonable to expect consistent interpretations with this approach.(3) There is a similar issue with the use of Capacity and Energy Emergencies. The defined terms are Capacity Emergency and Energy Emergency but by putting the "and" between the two, it looks Capacity is a defined term. (4) In regard to the "Emergency Operating Plan," does this apply to "Energy Emergencies" or "Capacity Emergencies," or just "Emergencies"? Wouldn't it be easier for the requirement to drop the word "Emergency" and require an "Operating Plan" instead? The definition of an Operating Plan includes an example of restoration activities, which is very close to what the drafting team is trying to convey. There is not a benefit for combining the terms, as a single term would suffice.(5) If an entity is registered as both a BA and a TOP, would they need two operating plans to address the differences in R1 and R2? If so, we recommend revising these requirements to eliminate duplicative efforts for compliance purposes. EOP SDT: The SDT was not defining a new term when it was capitalizing the term Operator at the beginning of a sentence. The SDT has removed the term "Emergency" from "Emergency Operating Plan" and has settled on "Operating Plan" throughout the document and added the define terms of "Capacity Emergency" and "Energy Emergency." The SDT understands that the an Operating Plan could be used for both the Balancing Authority and Transmission Operator, but the SDT separated out the requirements as they relate to the Balancing Authority and Transmission Operator. The requirements remain separate and applicable to each Entity.
PacifiCorp	No	PacifiCorp generally supports the added term "Operator-Controlled" preceding "manual Load shedding" in parts of Requirements R1 and R2. Added clarity for R1 and R2 would be provided by including portions of the Rationale section in the Requirement. Therefore, PacifiCorp recommends the Standard Drafting Team include a stand alone subrequirement in R1 and R2 pertaining to Load shedding, which reads as follows: "For Load shedding plans, automatic Load

Organization	Yes or No	Question 1 Comment
		shedding schemes are an important backstop against cascading outages or system collapse. If an entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. The Emergency Operating Plan shall include Operator-Controlled manual Load shedding plan(s) coordinated to minimize the use of automatic Load shedding." EOP SDT: The SDT appreciates your comments and have modified the requirements that they believe add the necessary clarity that your comment recommends.
American Electric Power	No	AEP has no objection to the qualifier "Operator-controlled", however each unique situation would dictate whether the appropriate action to take would be manual or automatic. R1 should allow such flexibility in the strategies specified. EOP SDT: The SDT appreciates your comments and have modified the requirements that they believe still allows for the flexibility needed during times when an Operator needs to take action.
NV Energy	No	The continued inclusion of the concept of coordination (or separation) of the Operator-Controlled manual Load shedding with the automatic underfrequency Load shedding is inappropriate for reliability, and the vague and ambiguous language raises auditability concerns. Underfrequency load shedding schemes are carefully coordinated across the Region to ensure that prescribed percentage steps of an area's load are shed at specific system frequency levels. The subrequirements R1.2.6 and R2.4.8 both convey that an entity should strive to minimize any overlap between its manual load shedding circuits and those that will be shed automatically by underfrequency. This approach results in an undesirable skewing of the percentage of an entity's load that will be shed by its underfrequency program. Specifically, the shedding of an entity's load manually, if the load is completely separate from the underfrequency circuits, will increase the percentage of remaining load that is to be shed by the entity's underfrequency program, jeopardizing the desired balance of the Regional underfrequency program coordination.The sub-requirements R1.2.6 and R2.4.8 are written with vague language. Taking the parent Requirements R1 and R2 into account, the entity is to develop maintain, and implement a Plan, which at a minimum, shall include: Strategies to prepare for and mitigate Emergencies including: Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding. As written, it is unclear what evidence would demonstrate adequacy with satisfaction of these requirements. The Rationale statements for R1 and R2 speak to the Entity evaluating their automatic load shedding schemes and coordinating so that overlapping use of Loads is avoided to the extent

Organization	Yes or No	Question 1 Comment
		reasonably possible, but there is no clarity as to what threshold an auditor would accept for the resultant overlap. Particularly, given the consequence of over-shedding automatic underfrequency loads if one were to fully segregate manual load shed circuits from automatic load shed circuits as explained above, it does not appear that these two sub-requirements promote BES reliability. We recommend removal of both sub-requirements R1.2.6 and R2.4.8, and addressing these matters in relevant NERC guidance documents. EOP SDT: The SDT appreciates your comments, but believe that it is important to retain the requirements, as modified, based on industry comments.
Wisconsin Electric	No	The term "Operator-controlled" with respect to load shedding is not adequately defined. Control could be interpreted to be via EMS/SCADA functionality or by dispatch of personnel executing switching. EOP SDT: The SDT appreciates your comments and have reflected your concerns in the requirement and rationale.
Northeast Power Coordinating Council	Yes	For consistency with the Rationale listed for R2 pertaining to "If any Parts of Requirement R2 are not applicable", a similar statement should be listed under the Rationale for R1. Suggest adding the wording: "If any Parts of Requirement R1, Part 1.2 are not applicable, the Transmission Operator should note 'not applicable' in their plan." EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised requirements.
The FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	We think that "Operator-Controlled" is redundant as "manual load shedding" requires that it is initiated and operated by someone. We do not object, but think it unnecessary. EOP SDT: The SDT appreciates your comments but, after discussion of the comments, the SDT has retained the words "Operator-controlled."
MRO NERC Standards Review Forum	Yes	
Peak Reliability	Yes	
Dominion	Yes	For consistency with the Rationale listed for R2 pertaining to "any Parts of Requirement R2 are not applicable", a similar statement should be listed under the rationale for R1. Dominion

Organization	Yes or No	Question 1 Comment
		suggests adding; If any Parts of Requirement R1, Part 1.2 are not applicable, the Transmission Operator should note "not applicable' in their plan. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised requirements.
SPP Standards Review Group	Yes	However, as written Requirement R1, Part 1.2.6 requires that the manual Load shedding plan minimize the use of automatic Load shedding. We believe the intent of the drafting team is for the requirement to state that the manual Load shedding plan should minimize the shedding of Load contained in the automatic Load shedding program. Otherwise the requirement reads that automatic Load shedding is a part of the manual Load shedding plan. We suggest the following language change for clarification: 'Operator-controlled manual Load shedding plan coordinated to minimize the amount of load designated in both the manual Load shedding and automatic Load shedding programs;'. This same comment would also apply to Requirement 2, Part 2.4.8. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised requirements.
SERC OC Review Group	Yes	For consistency with the Rationale listed for R2 pertaining to "any Parts of Requirement R2 are not applicable", a similar statement should be listed under the rationale for R1. The SERC OC Review Group suggests adding; If any Parts of Requirement R1, Part 1.2 are not applicable, the Transmission Operator should note "not applicable' in their plan. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised requirements.
Florida Municipal Power Agency	Yes	FMPA supports the comments submitted by FRCC.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern	Yes	

Organization	Yes or No	Question 1 Comment
Company Generation and Energy Marketing		
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	
ISO/RTO Cojuncil Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Wind Energy Transmission Texas, LLC	Yes	
Independent Electricity System Operator	Yes	
CenterPoint Energy Houston Electric, LLC	Yes	
Xcel Energy	Yes	
Public Utility District No. 1 of Cowlitz County, WA	Yes	However, PUD No. 1 of Cowlitz County, WA (District) finds the following sentence in the Rationale for R1 to be awkward: “It is the EOP SDT’s intent for Requirement R1 Part 1.2.6 that what is unwanted is the use manual Load shedding which is already armed for automatic Load shedding.” The District also finds the following phrase in the Rationale for R2 “...is to minimize as much as possible the use manual Load shedding...” is missing the word “of” between “use” and “manual,” or might be improved with the words “the use” being replaced with “using.” The District suggests using similar construct for both rationales, with a preference with the verbiage used for Requirement R2. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised rational statements.
Manitoba Hydro	Yes	

Organization	Yes or No	Question 1 Comment
Lincoln Electric System	Yes	
MidAmerican Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Idaho Power Co.	Yes	The addition of Operator-Controlled does not seem to change the intent of the requirement. The extent of operator control may be just limited to activating the load shedding application in EMS. I don't agree or disagree with the change. EOP SDT: The SDT appreciates your comments.
American Transmission Company LLC	Yes	
Texas Reliability Entity	Yes	
Ameren	Yes	
Tacoma Power	Yes	
Salt River Project	Yes	
PPL NERC Registered Affiliates		These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.

2. **Based on comments from a majority of stakeholders, the EOP SDT removed Requirement 3 from EOP-011-1 draft 1 and has placed the requirement on the Balancing Authority and Transmission Operator to coordinate their Emergency Operating Plans with impacted Balancing Authorities and Transmission Operators. Do you agree with this revision? If not, please provide specific suggestions for change in the comment area.**

Summary Consideration: The EOP SDT appreciates the comments received from the industry. Based on the feedback received, the EOP SDT deleted Requirements R1.3 and R2.5. The EOP SDT then redrafted Requirement R3 to have the Reliability Coordinator review and determine reliability risks that exist between Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. In making these revisions, the EOP SDT has made it the responsibility of the Reliability Coordinator to look for potential reliability risks between multiple plans. The EOP SDT has created a new Requirement R4; whereas, that if problems are identified by the Reliability Coordinator, the impacted Balancing Authorities or Transmission Operators must correct their plans within a timeframe specified by the Reliability Coordinator and resubmit the plans.

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	No	AZPS supported the inclusion of Requirement 3 in the standard. The role of the Reliability Coordinator is one of oversight and coordination. They have the wide-area viewpoint necessary to assess emergency operations plans in aggregate and see the interdependencies of the plans. AZPS recognizes that this updated proposal still has the RC included in an approver role but contends that the coordination piece is of equal importance. The standard now simply requires RC approval. There is no implication in the language that the RC should be reviewing all plans in aggregate looking for the regional impact of the combined plans. AZPS suggests that the RC is appropriate entity to both coordinate and approve the plans. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Duke Energy	No	We suggest revising R1.1.3 and R2.5 as follows:”Strategies for coordinating the Emergency Operating Plans of Balancing Authorities and Transmission Operators identified in their Emergency Operating Plan(s).We believe that the use of term “impacted” is too broad in the context of this requirement.

Organization	Yes or No	Question 2 Comment
		EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
ACES Standards Collaborators	No	We question the rationale of removing Requirement R3. Coordinating emergency operations in an RC Area is ultimately responsibility of the RC. We do not understand the rationale of transferring the responsibility to the TOPs and BAs in an RC Area. Our concern with this approach is the potential scrutiny from an auditor that the registered entity did not coordinate with all "impacted" BAs and TOPs. The requirement is vague as currently written. It's theoretically possible that a BA or TOP in each interconnection would need to coordinate with every other BA or TOP in the same interconnection for emergency operations. As written, auditors could scrutinize the list of coordinating BAs and TOPs and state that there was not enough coordination for emergency operations. Is this the intent of coordination from the drafting team? If so, then we disagree with the approach and request the drafting team clearly define the scope of coordination. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
American Electric Power	No	AEP disagrees with the change, and recommends that this requirement return to the approach proposed in the previous draft. AEP believes the Reliability Coordinator is in the best position to take the lead in coordinating its Balancing Authority and Transmission Operator plans. This form of coordination could involve the Reliability Coordinator reviewing the plans to ensure that the plans are compatible with the RC overarching plan (FERC Order No 693 Paragraph 548 hints at the Reliability Coordinator having an "overarching plan.") and support reliability of the Bulk Electric System. FERC Order No 693, Paragraph 547 states in part "While balancing authorities and transmission operators are capable of developing, maintaining and implementing plans to mitigate operating emergencies for their specific areas of responsibility, unlike reliability coordinators, they do not have wide-area views." We are in favor of the Reliability Coordinator hosting workshops as a platform to allow its local Balancing Authority and Transmission Operator to air the plans as another form of coordination (MISO presently hosts workshops to accomplish this coordination task for its members.). EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.

Organization	Yes or No	Question 2 Comment
CenterPoint Energy Houston Electric, LLC	No	Please see CenterPoint Energy response to Question 3. CenterPoint Energy believes the coordination of the Emergency Operating Plans of the TOPs and BAs within an RC area should be administered by the RC, similar to the approach taken by the FERC-approved EOP-010-1 GMD standard's R1.2. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Public Utility District No. 1 of Cowlitz County, WA	No	The District believes the SDT intent is to advance a results based requirement for each BA and TOP to make a good faith effort to coordinate the Emergency Operating Plans (Plans), both during development and their implementation. The District agrees with this; however, Requirement Parts 1.3 & 2.5 will not assure the Plans will be coordinated among mutually impacted BAs and TOPs. The requirement for strategies be included in each Plan and implemented for coordination appears to stop short of the above stated goal. It is also confusing: does this include coordination both in the Plan development and the actual implementation during an Energy Emergency? How should enforcement respond to an instance where one entity reaches out to another, but is unable to get a response or cooperation? The District suggests Parts 1.3 & 2.5 remain the same, but that the Reliability Coordinator be tasked as part of the approval process to affirm coordination has been achieved. Please refer to comments responding to question 3. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Puget Sound Energy	No	It is difficult to determine whether the language in parts 1.3 and 2.5 requires the coordination of the plans during the development phase, during the implementation phase or both. The previous R3 appears to have addressed coordination during the development phase, but the structure of the current language seems to be more suited for coordination during the implementation phase. If the second option is the case, the SDT should consider revising the language to something like "Strategies for coordinating the implementation of Emergency Operating Plans..." EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
MidAmerican Energy	No	R1.3 and R2.5 state that strategies are required to coordinate Emergency Operating Plans with impact TOPs and BAs. The NSRF questions this. Each TOP or BA can have strategies between impacted TOPs and BAs and the RC can still disapprove of their coordinated plans, per R3. The amount of effort between TOPs and BAs "prior" to

Organization	Yes or No	Question 2 Comment
		submission to the RC could be rather great. The impacted entities may have perfectly coordinated plans but the RC could still disapprove them. The NSRF understands that the BA's and TOP's plans need to support the RC's plans. This will assure a steady state system during emergencies. R1 and R2 already prescribe that each TOP and BA have RC approved Emergency Operating Plans. Thus, we recommend that R1.3 and R2.5 be deleted. The RC has totoal control over their RC area and are best suited to approve all Emergency Operating Plans within their area of responsibility.R1.2.6 speaks of "coordination" between the TOP's manual Load shedding plans and the use of automatic Load shedding. This is clearly stated in the Rational box for R1.2.6 but the Requirement reads differently. Recommend R1.2.6 to read: "Operator-controlled manual Load shedding plan coordinated to minimize the over lapping with the use of automatic Load shedding; . Or read similar to the recommendation of R2.4.8. Another possible solution would be the following wording of "Operator-controlled manual and automatic load shedding programs have sufficient separation of loads between the programs to perform each of their respective intended plan functions". R2.4.8 reads similar to R1.2.6. But the Rational boxes are different, recommend that both Rationals read the same with the addition of "The reference is not intended to require coordination with other entities" be added to R1 Rational box. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4. As it relates to your comments about Load shedding, please see the Summary of Comments for Question 1.
Texas Reliability Entity	No	As currently written, Requirements R1 and R2 do not explicitly state that the BA and TOP shall coordinate their EOPs with impacted BAs and TOPs. R1.3 and R2.5 state that the TOP and BA, respectively, shall have EOPs that include "Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities." The requirement to have a strategy is not the same as requiring the TOP and BA to coordinate with impacted BAs and TOPs. As such, the requirement to coordinate from the removed Requirement R3 is no longer covered in the standard. Therefore the failure to coordinate is not enforceable and the reliability benefit is lost. Texas Reliability Entity, Inc. (Texas RE) recommends the EOP SDT consider adding a requirement as follows: "Each Balancing Authority and Transmission Operator shall coordinate their Emergency Operating Plans with the other Balancing Authorities and

Organization	Yes or No	Question 2 Comment
		Transmission Operators in their Reliability Coordinator Area to assure that the plans are compatible and support reliability in the Reliability Coordinator Area." Adding a requirement to coordinate would also require an addition to the VSL. Texas RE suggests the SDT add a Severe only VSL for failure to coordinate with all BAs and TOPs in their RC Area. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement 3 and newly written Requirement 4.
Ameren	No	We believe that the RC should take responsibility for the coordination, at least at the transmission level. Below the transmission level it could be the BA and TOP. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Northeast Power Coordinating Council	Yes	We agree that Emergency Operating Plans should be coordinated. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
The FRCC Operating Committee (Member Services)	Yes	
Colorado Springs Utilities	Yes	
MRO NERC Standards Review Forum	Yes	R1.3 and R2.5 state that strategies are required to coordinate Emergency Operating Plans with impact TOPs and BAs. The NSRF questions this. Each TOP or BA can have strategies between impacted TOPs and BAs and the RC can still disapprove of their coordinated plans, per R3. The amount of effort between TOPs and BAs "prior" to submission to the RC could be rather great. The impacted entities may have perfectly coordinated plans but the RC could still disapprove them. The NSRF understands that the BA's and TOP's plans need to support the RC's plans. This will assure a steady state system during emergencies. R1 and R2 already prescribe that each TOP and BA have RC approved Emergency Operating Plans. Thus, we recommend that R1.3 and R2.5 be deleted. The RC has totoal control over their RC area and are best suited to approve all Emergency Operating Plans within their area of responsibility.R1.2.6 speaks of "coordination" between the TOP's manual Load shedding plans and the use of automatic Load shedding. This is clearly stated in the Rational box for R1.2.6 but the Requirement reads differently. Recommend R1.2.6 to read: "Operator-controlled manual Load shedding plan coordinated to minimize the over lapping with the use of automatic Load shedding; . Or read similar to the recommendation of R2.4.8. Another

Organization	Yes or No	Question 2 Comment
		possible solution would be the following wording of "Operator-controlled manual and automatic load shedding programs have sufficient separation of loads between the programs to perform each of their respective intended plan functions". R2.4.8 reads similar to R1.2.6. But the Rational boxes are different, recommend that both Rationals read the same with the addition of "The reference is not intended to require coordination with other entities" be added to R1 Rational box. EOP SDT: EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4. As it relates to your comments about Load shedding, please see the Summary of Comments for Question 1.
Peak Reliability	Yes	
Dominion	Yes	We agree that Emergency Operating Plans should be coordinated. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
SPP Standards Review Group	Yes	
DTE Electric	Yes	
JEA	Yes	
SERC OC Review Group	Yes	The SERC OC Review Group agrees that Emergency Operating Plans should be coordinated. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Florida Municipal Power Agency	Yes	FMPA supports the comments submitted by FRCC.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	

Organization	Yes or No	Question 2 Comment
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	FOR EOP-011-1 R1 PART 1.3 AND R2 PART 2.5: REPLACE: “with impacted Balancing Autorities and Transmission Operators” WITH: “with Balancing Authorities and Transmission Operators known to be impacted by those plans.” RATIONALE: Compliance concerns with the current wording will likely drive email blasts to neighboring TOPs and BAs, and possibly all within the same Interconnection, thereby creating a volume of insignificant notifications such that notifications containing significant impacts are more likely be overlooked and BES reliability diminished. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
ISO/RTO Cojuncil Standards Review Committee	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
Wind Energy Transmission Texas, LLC	Yes	
Independent Electricity System Operator	Yes	
ReliabilityFirst	Yes	
Xcel Energy	Yes	
Manitoba Hydro	Yes	
Lincoln Electric System	Yes	
Oncor Electric Delivery LLC	Yes	
Idaho Power Co.	Yes	I was unable to find the requirement for coordinating Emergency Operating Plans with impacted Balancing Authorities and Transmission Operators. Requirement 1.3 says " Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities" this seems a little vague.

Organization	Yes or No	Question 2 Comment
		EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
American Transmission Company LLC	Yes	
NV Energy	Yes	
Wisconsin Electric	Yes	
Tacoma Power	Yes	
Salt River Project	Yes	

3. The EOP SDT received several comments regarding Reliability Coordinator approval of Balancing Authority and Transmission Operator Emergency Operating Plans. The FERC directive in Paragraph 548 or Order No. 693 mandates that the Reliability Coordinator be included as an applicable entity; while plan approval by the Reliability Coordinator was not a specific mandated intent, the EOP SDT believes that approval by the Reliability Coordinator reduces risk to reliability of the BES. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.

Summary Consideration: The EOP SDT appreciates the comments received from the industry. Based on the feedback received, the EOP SDT deleted Requirement R1.3 and R2.5. The EOP SDT then redrafted Requirement R3 to have the Reliability Coordinator review and determine reliability risks that exist between Transmission Operators and Balancing Authorities within its Reliability Coordinator Area. In making these revisions, the EOP SDT has made it the responsibility of the Reliability Coordinator to look for potential reliability risks between multiple plans. The EOP SDT has created a new Requirement R4; whereas, that if problems are identified by the Reliability Coordinator, the impacted Balancing Authorities or Transmission Operators must correct their plans within a time frame specified by the Reliability Coordinator and resubmit the plans.

Organization	Yes or No	Question 3 Comment
Northeast Power Coordinating Council	Yes	We are concerned with the RC obligation to simply approve the TOP/BA EOPs. It implies that approval could be checking compliance. The Requirement or the Technical Guidance should provide direction and meaning to the approval. If the SDT was to codify the requirement then we would like to suggest language consistent with EOP-006.

Organization	Yes or No	Question 3 Comment
		Suggest:R3. Each Reliability Coordinator shall review the Emergency Operating Plans (EOPs) of the Transmission Operators and Balancing Authority within its Reliability Coordinator Area. 3.1 The Reliability Coordinator shall determine whether the Transmission Operator's or Balancing Authority's EOP is coordinated and compatible with the Reliability Coordinator's EOP and other Transmission Operators' EOPs within its Reliability Coordinator Area. The Reliability Coordinator shall approve or disapprove, with reasons stated, the Transmission Operator's or Balancing Authority's submitted EOP within 30 calendar days following the receipt of the EOP from the Transmission Operator or Balancing Authority. As an alternative, a section in the Guidelines and Technical Basis could be written to provide guidance. The RC role in the TOP or BA process to develop an EOP can vary based on the quantity of Emergency Operating Plans being submitted. When an RC provides its approval of a submitted EOP the RC must review the submitted EOP to verify it is compatible and coordinated with the RC's overarching emergency operating plans developed for its Wide Area responsibility. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
The FRCC Operating Committee (Member Services)	No	We do not feel that the approach by the SDT is fully responsive to the FERC directive nor is it consistent with the desire expressed in the order. In addition there is lack of clarity on what criteria the RCs should use to approve or disapprove individual TOP and BA plans. The requirement as written appears to simply add administrative burden and compliance implications that add little to improving reliability. Adding an "auditing" purpose to RCs duplicates compliance monitoring oversight of TOP and BA entities inappropriately and should not be added to the responsibility of RCs. We do acknowledge that the RC role is important in coordinating response to Emergencies however, contrary to EOP-006 (restoration) where the RC has a central role in guiding System restoration, individual BA and TOP responses to emergencies within their area is a much different operating scenario and the RCs role are likely to be very different. If the SDT determines that it is essential to have the RC involved in the approval process, we request criteria be provided for consistency otherwise criteria could be created by individual RCs and inconsistently applied across interconnections. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.

Organization	Yes or No	Question 3 Comment
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	
MRO NERC Standards Review Forum	Yes	The NSRF believes that with the RC approving Emergency Operating Plans, that they are "coordinating (align) Emergency Operating Plans within their RC area. This approveal process will reduce the risk of instability during emergencies. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
FirstEnergy Corp		
Peak Reliability	Yes	
Dominion	Yes	We agree that the SDT met the FERC directive and we also cite the comments of many as providing justification requiring such approval. In some areas, generation scheduling, dispatch and outage approval is done by an entity registered solely as BA while in others it is done by an entity that may be registered as BA and TOP. In others it is done by an entity registered as BA, TOP and RC. In order for this standard to accommodate these variations, we support a requirement that, at a minimum, requires the RC insure the individual plans are coordinated such that they can be utilized in an aggregated manner when necessary to maintain relibiability within the RCs reliability area. We could make similar statements relative to manual load shedding. BAs typically do not have field personnel and therefore must rely upon manual load shed plan 'owned' by an entity with such personnel (typically DP). In this case, it is appropriate for the BA's load shed plan to consist of contacting that entity (or entities) and directing a specified amount of load be shed within a defined amount of time. It is also appropriate for the BA's load shed plan to consist of contacting its RC and requesting that a specified amount of load be shed within a defined amount of time. In this example, the RC would then have to contact one or more entities directing them to shed a specified amount of load be shed within a defined amount of time. In either case, the RC would have reviewed and approved the Emergency Operating Plan developed by each BA and TOP within its reliability area based upon insuring that these plans are coordinated as necessary. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
SPP Standards Review Group	Yes	

Organization	Yes or No	Question 3 Comment
Tennessee Valley Authority		
DTE Electric	Yes	
PPL NERC Registered Affiliates	Yes	Requirement R3 specifies the amount of time the RC has to approve a BA or TOP's EOP; however, it does not specify the amount of time a TO or BA has to revise and resubmit the EOP in the event that an RC does not approve the initial submission.â€ƒ EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
JEA	No	The plan should not be required to be approved by the RC. We do not have a problem coordinating with them and providing them a copy as current standards require. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
SERC OC Review Group	Yes	
Seattle City Light	No	Seattle believes that while approval of emergency oeprating plans by the Reliability Coordinator might add BES reliability, it adds more compliance burden than it does add BES reliability. In addition, requiring separate approvals for TOP and BA emergency operating plans may reduce reliability for those entities such as Seattle that are both TOP and BA, because emergency plans that presently integrate TOP and BA activities will need to be made separate purely for compliance purposes. This separation will add unnecessary complexity and duplication to emergency plans, and offers potential for confusion during an emergency situation as opposed to a single integrated plan. Seattle recommends 1) that the SDT follow paragraph 548 of Order 693 as worded, and delete the requirement for approval of emergency plans by the Reliability Coordinator and 2) revise R1 and R2 to allow a single integrated emergency plan for entities that are both TOP and BA (which is common in WECC and represents a substantial fraction of the BAs existing within NERC). EOP SDT: EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4. The SDT understands that the an Operating Plan could be used for both the Balancing Authority and Transmission Operator, but the SDT separated the requirements that relate to the Balancing Authority and Transmission Operator. The requirements remain separate and applicable to each entity. The plan could be used for an entity that is registered as both BA and TOP.

Organization	Yes or No	Question 3 Comment
Florida Municipal Power Agency	No	FMPA supports the comments submitted by FRCC.
Duke Energy	No	Duke Energy is unclear on the justification of requiring an RC to approve the Emergency Operating Plans of a BA or TOP. Is there specific technical justification for the approval, and if so, does it add to the reliability of the BES? We understand that in Order 693, FERC directed that the RC be included as an applicable entity. However, we do not believe that this "inclusion" should necessarily rise to the level of being the approver of a BA or TOP's Emergency Operating Plan. We feel that it would be more appropriate for an RC to be "knowledgeable and aware of all Emergency Operating Plans submitted" by the BA(s) and TOP(s) in its RC area. If the SDT determines that it is essential to have the RC(s) approve Emergency Operating Plan(s) developed by a BA and TOP, then we suggest that criteria be established to provide a consistent, measurable approach throughout the industry. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	Southern understands the SDT's attempt to address the FERC directive from Order No. 693 to include the reliability coordinator as a necessary entity. Our concern, however, is the operational expectations (and potential compliance implications) of the wording as it stands using the word "approve" and the lack of guidance on what basis approval would be given. Southern agrees with FERC, as acknowledged in its Order for EOP-006, that approval of these plans does not guarantee that they will adequately mitigate an Emergency for a BA/TOP but merely that the plans are compatible and support reliability. Reviewing the various definitions of "approve" indicates it means to "judge favorably or good". Without indicating the context upon which to "judge goodness" one might infer that it includes opportunity for operational success. Due to the details unique to each BA and TOP, only those entities are in a position to judge goodness with regard to operational success. The RC is not in a position to judge such details. The RC role should be limited to reviewing against a specific set of criteria. The RC could participate, as FERC expects, by reviewing the plans and notifying the submitting BA/TOP of issues in their plan based on incompatibility with neighboring BA/TOP emergency operating plans, the potential to create risk to wide area reliability, and incompatibility with RC distributed emergency operating plans. "Approval" and any associated implications on potential success would be avoided.Suggested alternate wording for R3 might be:Each Reliability Coordinator shall review Emergency Operating Plans submitted by Transmission

Organization	Yes or No	Question 3 Comment
		Operators and Balancing Authorities in its RC Area on the basis of a plan element's incompatibility with and non-reciprocal inter-dependency on neighboring BA/TOP emergency operating plans, the potential to create additional risk to wide-area reliability, and incompatibility with RC distributed emergency operating plans and then, within 30 calendar days of submittal, notify the submitting Transmission Operators and Balancing Authorities of any incompatibilities and/or reliability risks identified in the submittal.In addition, the SDT should include a companion requirement for BAs/TOPs to address any incompatibilities and/or reliability risks identified by their RC within a defined time period after being notified of such incompatibilities / reliability risks and certainly prior to the effective date of the Emergency Operating Plans. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	Yes	
ACES Standards Collaborators	No	As stated above, the RC should be the responsible entity to coordinate emergency operations in its area. The drafting team needs to consider requiring the RC to coordinate emergency operations with the applicable TOPs and BAs in its RC Area. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Associated Electric Cooperative, Inc. - JRO00088	Yes	AECI agrees that this requirement provides opportunity for reduced risk to reliability, but disagrees with the assertion that it necessarily reduces risk. EOP SDT: The SDT appreciates your comments.
ISO/RTO Cojuncil Standards Review Committee	No	We are concerned with the lack of detail in the R3 requirement for the RC to approve the EOPs of the TOPs and BA. R3 should include a requirement for the BA and TOP to submit their proposed EOPs to the RC. Also, the lack of detail and criteria for approval in R3 could lead to a misinterpretation that RC approval involves checking compliance. We would like to suggest the following alternative language, which is along the lines of what is currently contained in EOP-005-2 and EOP-006-2:R3. Each Transmission Operator and Balancing Authority shall submit its proposed Emergency Operating Plan and any subsequent proposed changes to its Emergency Operating Plan to its Reliability Coordinator.3.1 The Reliability Coordinator shall review each proposed Emergency Operating Plan it receives

Organization	Yes or No	Question 3 Comment
		from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area and determine whether the Emergency Operating Plan is coordinated and compatible with the Reliability Coordinator's Emergency Operating Plan and shall approve or disapprove, with stated reasons for disapproval, the Emergency Operating Plan within 30 calendar days following the receipt of the Emergency Operating Plan from the Transmission Operator or Balancing Authority.Alternative, 3.1 can be stated as a separate requirement to avoid the confusion of having multiple entities in one requirements having different mandates.Note that ERCOT does not support this comment. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
NERC		
Wind Energy Transmission Texas, LLC	No	The proposed EOP change only further places unnecessary burden on the RC. We cannot understand why the RC should need to approve a company specific emergency plan. We have no issues with coordinating our EOP with the RC and neighboring TOPs, but we do not agree with requiring RC approval of company specific EOPs. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Independent Electricity System Operator	Yes	
American Electric Power	No	AEP does not support the Reliability Coordinator formally approving the Balancing Authority and Transmission Operator Emergency Plans. In FERC Order No. 693, Paragraph 632 (EOP-006-1), FERC clearly requires the Reliability Coordinator to be involved in the development and approval of restoration plans. FERC did not make this distinction of the Reliability Coordinator approving the EOP (EOP-001-0) plans. We believe EOP-011-1 R3 violates the intent of Paragraph 81 criteria B1. AEP supports the Reliability Coordinator role as a coordinator of the Operator plans as noted in our response to question #2. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
ReliabilityFirst	No	1. Requirement R1 and R2a. The following comment was supplied during the previous comment period and ReliabilityFirst believes it was not addressed.

Organization	Yes or No	Question 3 Comment
		ReliabilityFirst requests the following comment be responded to: ReliabilityFirst believes the "implement a Reliability Coordinator-approved Emergency Operating Plan" language is troublesome in a scenario where a Reliability Coordinator disapproves the Emergency Operating Plan (per Requirement R4). In this scenario, the Transmission Operator/Balancing Authority could be compliant with developing and maintaining the plan but without Reliability Coordinator approval of the plan, the Transmission Operator/Balancing Authority could potentially be deemed non-compliant with Requirement R1 and R2. ReliabilityFirst believes the "implement a Reliability Coordinator-approved Emergency Operating Plan" language should be taken out of Requirements R1 and R2 respectively. ReliabilityFirst recommends including a new Requirement R5 which states "Upon Reliability Coordinator approval of the Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans, the Transmission Operator and Balancing Authority shall implement the approved Emergency Operating Plan." EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
CenterPoint Energy Houston Electric, LLC	No	Since FERC did not mandate RC approval in Paragraph 548, CenterPoint Energy does not believe that using RC approval is the most sensible method to satisfy FERC's directive. Instead, CenterPoint Energy recommends that EOP-011-1 adopts an approach similar to the FERC-approved EOP-010-1 GMD standard. Thus, for R1: "Each RC shall develop, maintain, and implement an Emergency Operating Plan that coordinates Emergency Operating Procedures or Emergency Operating Processes within its RC Area. The Emergency Operating Plan shall include a process for the RC to review and to coordinate the Emergency Operating Procedures or Emergency Operating Processes of the TOPs and BAs within its RC Area." For R2: "Each TOP shall develop, maintain, and implement Emergency Operating Procedures or Emergency Operating Processes to mitigate operating Emergencies on its Transmission system. At a minimum, the Operating Procedures or Operating Processes shall include the following elements:...". For R3: "Each BA shall develop, maintain, and implement Emergency Operating Procedures or Emergency Operating Processes to mitigate Capacity and Energy Emergencies. At a minimum, the Operating Procedures or Operating Processes shall include the following elements:...".

Organization	Yes or No	Question 3 Comment
		EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
South Carolina Electric and Gas		
Seminole Electric Cooperative, Inc.		
FRCC		
Xcel Energy	Yes	
Public Utility District No. 1 of Cowlitz County, WA	No	The District agrees with the concept, but finds there are no defined elements the RC should follow before issuing approval or disapproval of an Emergency Operating Plan (Plan). Please see comment to question 2. The SDT's intent appears not to encompass a goal of assuring each plan is compliant before approval. Rather, the intent appears merely to establish an opportunity to reduce risk to the BES. While the District does not believe the RC should be placed in the compliance auditor's role, there is concern that the approval process will greatly vary depending upon the particular RC, or the amount of time available to review Plans. While a 30-day allowance to review a single Plan for approval or disapproval may be reasonable, the SDT should consider instances where the RC will need to review many Plans together as an interweaving coordinated effort for a large operational footprint. Further, the SDT should consider establishing minimum Plan review objectives before Plan approval is granted. Otherwise, the RC will be allowed to rubberstamp Plans with little or no serious review. The District proposes the following be considered: 1) require the RC to review each submitted Plan and document findings. 2) Approval or disapproval of a Plan is based on the findings from the review. 3) Allow the RC to issue conditional approval subject to further review when additional time is required to analyze coordination with other impacted TOPs and BAs. 4) Require the RC to retain an up-to-date archive of all Plans within its footprint to assist its review for coordination between plans and application for lessons learned. 5) Require the RC to recall an approved Plan when it discovers a weakness or gap, and give notice to the affected entity why the Plan has been recalled. 6) Require entities that have been given notice of a recalled Plan to submit a revised Plan for approval. 7) Consider whether or not the RC should be given expressed final authority to resolve coordination issues between plans. EOP SDT: EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written

Organization	Yes or No	Question 3 Comment
		Requirement R4. The other provided comments that require additional RC oversight may help define process, the EOP SDT believes they tend to be administrative in nature and should not be addressed in this standard.
Manitoba Hydro	Yes	
Kansas City Power & Light		
Lincoln Electric System	Yes	
Puget Sound Energy	No	Imposition of an RC approval process for these plans will impose a significant burden on the RCs, as well as on the BAs and TOPs. It would be better to model the required coordination after the approach implemented in IRO-010 - where the RC specifies additional requirements for the plans and the BAs and TOPs are required to comply with those specifications. This approach will allow an RC to address specific interconnection and RC area issues, but does not impose the significant administrative burden of coordination with each BA and TOP within its area. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
California ISO		
MidAmerican Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Idaho Power Co.	No	The new R3 says that the RC will approve or disapprove the submitted plans. If they are charged with approving a plan it seems there should be some requirement to ensure that they are coordinated. With the elemination of the old R3 the approval seems incomplete.The Reliability Coordinator must be able to access all BA and TOP Emergency Procedures and have the ability to ensure that procedures are coordinated and do not conflict with each other. However to require the Reliability Coordinator to Approve all Emergency Operating plans will increase the burden on all entites involved with little increase in system reliability.IPC System Planning like that the change assumes some level of coordination between the RC and TOPs. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
American Transmission Company LLC	Yes	
Hydro-Quebec TransEnergie		

Organization	Yes or No	Question 3 Comment
Texas Reliability Entity	No	RC approval of the TOP EOPs places an unnecessary burden on both entities, particularly in cases where plan updates may be administrative in nature. Also, by approving the TOP EOPs, the RC may be accepting an unnecessary legal risk by accepting a plan as sufficient and adequate to ensure reliability when they do not necessarily have detailed knowledge of the systems for which the EOPs were developed. The RC review, if any, should only ensure that the emergency plans are coordinated and compatible with the overall RC EOP and other entity plans in the RC area. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
NV Energy	Yes	We agree that the inclusion of the RC is achieved through the proposed provision of approval of the emergency plans. The Standard, however, is noticeably silent on the protocols that would be expected in the event that the RC is unable to approve one or more Plans, either the Transmission of Energy Emergency Plans. For instance, if the RC reviews a Plan but finds fault in it, how will compliance with the 30-day approval time limit be achieved? Further, what is the status of compliance of the Entity whose submitted Plan is returned for revision? There would be a period of time wherein the Entity may be operating under its Plan without attaining approval from the RC. Is the Entity in jeopardy of non-compliance by operating under an unapproved Plan? The VSLs don't address this possibility. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4. While a submitted plan may require additional changes as identified by the RC, this does not invalidate already-reviewed plans and would not place the Entity in a compliance risk.
Exelon Companies		
City of Tallahassee		
South Carolina Electric and Gas		
Illinois Municipal Electric Agency		
Wisconsin Electric	No	The standard as written does not sufficiently identify the criteria by which the RC would evaluate BA / TOP Emergency Operating Plans. The standard should include criteria similar to EOP-006, R5.1, potential language: The Reliability Coordinator shall determine whether the Emergency Operating Plan is coordinated and compatible with other Emergency Operating Plans within its Reliability Coordinator Area. The Reliability

Organization	Yes or No	Question 3 Comment
		Coordinator shall approve or disapprove, with stated reasons, the submitted emergency plan within 30 calendar days following the receipt of the plan from the BA/TOP. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.
Ameren	No	We believe that because the majority of manual load shedding is likely to be at sub-transmission voltage levels the RC will not have awareness of this load shedding and will need to rely on the TOP or BA for the specific details. EOP SDT: The SDT appreciates your comments.
Electric Reliability of Texas, Inc.	No	See response C. under Q7 below.
Tacoma Power	Yes	
Salt River Project	No	We do not agree that the RC approval is necessary to enhance reliability. The additional administrative burden for all of the applicable entities, including the RC, does not provide a significant enhancement to reliability. This burden includes evidence of submittal of the Plan to the RC, RC review of each plan in its footprint and evidence of RC approval for each entity. This is a significant burden for each entity that doesn't provide an equitable reliability enhancement. The EOP SDT should consider changing the language in requirements R1, R2 & R3 to state that emergency plan coordination with the RC is required, just as it is among BA's and TO's. The language could include a requirement for the RC to review each plan for coordination and effectiveness. We believe that the revised coordination language will satisfy the FERC Order 693 and minimize the administrative evidence burden on the applicable entities. EOP SDT: The SDT appreciates your comments and have reflected the recommendations you have made in the revised Requirement R3 and newly written Requirement R4.

4. The EOP SDT has removed Requirement R5 from EOP-011-1 draft 1, as it is redundant with currently-enforceable TOP-001-1a. Do you agree with this revision? If not, please explain in the comment area below

Summary Consideration: Comments received from industry were supportive of this change; EOP-011-1 retains the deletion of Requirement R5.

Organization	Yes or No	Question 4 Comment
CenterPoint Energy Houston Electric, LLC	No	CenterPoint Energy agrees with the SDT that EOP-011-1 draft 1's R5 is redundant with currently-enforceable TOP-001-1a and therefore should be removed. However, CenterPoint Energy disagrees with the SDT's subsequent decision to re-create the same redundant requirement as EOP-011-1 draft 2 R1.2.1. Therefore, draft 2's R1.2.1 should be deleted because of the SDT's stated redundancy. EOP SDT: The SDT appreciates your comments. The SDT believes it is still an important part of a BA or TOP Operating Plan to include processes on notifying and keeping the RC informed of the conditions.
Northeast Power Coordinating Council	Yes	
The FRCC Operating Committee (Member Services)	Yes	
Arizona Public Service Company	Yes	
Colorado Springs Utilities	Yes	

Organization	Yes or No	Question 4 Comment
MRO NERC Standards Review Forum	Yes	
Peak Reliability	Yes	BA requirement is still in R2.2
Dominion	Yes	
SPP Standards Review Group	Yes	
DTE Electric	Yes	
JEA	Yes	
SERC OC Review Group	Yes	
Seattle City Light	Yes	
Florida Municipal Power Agency	Yes	FMPA supports the comments submitted by FRCC.
Duke Energy	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company	Yes	

Organization	Yes or No	Question 4 Comment
Generation and Energy Marketing		
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	Yes	
ACES Standards Collaborators	Yes	We agree that redundant requirements should be removed. We also believe that combined glossary terms that lead to confusion and administrative tasks without reliability benefits should be removed. EOP SDT: The SDT appreciates your support and have redrafted terms so they should not be combined.
Associated Electric Cooperative, Inc. - JRO00088	Yes	
ISO/RTO Cojuncil Standards Review Committee	Yes	
PacifiCorp	Yes	
Bonneville Power Administration	Yes	
Wind Energy Transmission Texas, LLC	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 4 Comment
American Electric Power	Yes	AEP agrees, and appreciates the drafting team's willingness to accept our earlier recommendation that R5 be removed.
ReliabilityFirst	Yes	
Xcel Energy	Yes	
Public Utility District No. 1 of Cowlitz County, WA	Yes	
Manitoba Hydro	Yes	
Lincoln Electric System	Yes	
Puget Sound Energy	Yes	
MidAmerican Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Idaho Power Co.	Yes	
American Transmission Company LLC	Yes	
Texas Reliability Entity	Yes	Texas RE agrees with this revision. The requirement for a TOP to notify its RC of actual or expected emergencies is still in the draft TOP-001-3, as R8. EOP SDT: The SDT appreciates your support.
NV Energy	Yes	

Organization	Yes or No	Question 4 Comment
Wisconsin Electric	Yes	
Ameren	Yes	
Tacoma Power	Yes	
Salt River Project	Yes	

5. The EOP SDT has revised Attachment 1, removing “Operating Reserves” from EEA 2 and adding “Operating Reserves” into EEA 3. Do you agree with this change? If not, please explain in the comment area below

Summary Consideration: The EOP SDT appreciates the comments from the industry and have made changes to Attachment 1 that reflects the general concern that the industry would be shedding Load in order to maintain reserves. The SDT deleted 3.2 in the Attachment. The SDT also modified the “Circumstances” of EEA3 to read, “The energy deficient BA is unable to meet minimum Contingency Reserve requirements.” The SDT also eliminated the words “Inability to meet Operating Reserve requirement or,” from the EEA 3 “Title.” In addition, the SDT modified the “Circumstances” for EEA 2 that show that an entity will be in this level when it has implemented its Operating Plan to mitigate Emergencies but is still able to maintain Contingency reserves.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council	No	The proposed move of utilizing Operating Reserve (OR) from EEA 2 to EEA 3 does not present any problems. However, we are concerned with the added sentence that “In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement.” The sentence needs to be clarified. Even though the statement doesn’t stipulate that load has to be shed,

Organization	Yes or No	Question 5 Comment
		having to shed load can be construed. We do not agree that the deficient BA needs to shed firm load to meet the Operating Reserve requirement. Operating Reserve is carried to guard against demand variations and contingencies resulting from a loss of generating resource or import, and system contingencies. A BA should only shed load if a contingency occurs necessitating load reduction to restore system operation within well-defined limits. You do not operate to shed firm load to avoid having to shed firm load.The conclusion that may be reached is that a BA is required to shed firm load prior to committing its remaining Operating Reserves. This can be clarified by rephrasing to: In this situation, the requesting BA must be able to have an amount of firm Load shed if necessary to supplement its remaining Operating Reserves in order to meet its Operating Reserve requirement." EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
Arizona Public Service Company	No	This appears to constitute a change in the emergency response ideology. Under the current standard, it is not necessary to shed load to restore reserves at an EEA 2, unless they are called upon. The new proposal states that an entity must have the ability to shed load to restore reserves. The SDT has provided no rationale for this change. AZPS requests clarification on the rationale for this change if in fact the standard now states that firm customer load should be shed to restore reserves.As a secondary issue the movement of operating reserves from EEA 2 to EEA 3 is that it reduces the clarity of the EEA levels. The attachment to EOP-002-3.1 provides a clear trigger for each EEA level. Level 1 is triggered by having all resources in use while still maintaining the ability to meet all operating requirements. Level 2 is triggered by becoming reserve deficient while still maintaining the ability to meet all of your firm commitments. Level 3 is triggered by losing the ability to meet all of your firm commitments thereby becoming ACE deficient. The proposed changes leave the Level 1 trigger intact. The previous Level 2 trigger becomes the trigger for Level 3. This leaves no definitive trigger for Level 2. AZPS believes this will cause confusion as TOPs

Organization	Yes or No	Question 5 Comment
		transition between the EEA levels. Therefore AZPS recommends that the Operating Reserves remain in EEA 2 as in EOP-002-3.1. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments. The SDT reworked the circumstances for EEA 2 and, therefore, believe there are still definitive triggers between levels.
SPP Standards Review Group	No	By making this change, the drafting team is requiring deficient Balancing Authorities which can not maintain their Operating Reserve obligations to 'be able to' shed firm Load in order to maintain its reserve obligations. We seek clarification from the drafting team on whether the deficient Balancing Authority is required to actively shed load in order to maintain its reserves or only needs to have the capability to shed load to maintain its reserves. The drafting team has proposed this significant change without providing sufficient justification for the change. The proposed BAL-002-2 is referenced as the driver for this specific change. However, by our reading of the last posted version of BAL-002-2, R2 the responsible entity is given an exemption from needing to maintain its reserves if it has experienced a Contingency or is in an EEA 2 or EEA 3. The proposed language in EOP-011-1 is in direct conflict with this language. The exemption holds equally well for EEA 2 and EEA 3. So why change? Why move the Operating Reserve clause to EEA 3? We strongly recommend that the drafting team put the Operating Reserve clause back under EEA 2 where it belongs. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
DTE Electric	No	SDT did not provide rationale associated with this change.
PPL NERC Registered Affiliates	No	Operating Reserve requirement OR Firm Load interruption is imminent or in progress." The circumstance description in section 3 states that the "Requesting BA is unable to meet Operating Reserve requirements AND foresees a need for possible interruption of Firm Load." We feel that the STD inadvertently used the word "or" in the heading for Attachment A, section 3. We recommend that the heading be

Organization	Yes or No	Question 5 Comment
		changed to the following in order to make it consistent with the circumstance description in section 3."EEA 3 - Inability to meet Operating Reserve requirements and firm Load interruption is imminent or in progress."Note that firm load is not a defined term and should not be capitalized. If those changes are made, we would agree with the Operating Reserves being moved from EEA 2 to EEA 3. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments
SERC OC Review Group	No	The SERC OC Review Group feels there is still lack of understanding around the use of Operating Reserves vs. Contingency Reserves and believe further work is needed to provide better clarity. Changing the current definition of EEAs by moving the term Operating Reserves may not solve the conflict with BAL standards and adds unneeded complexity to this standard.Operating Reserves include Contingency Reserves and clarity should be added in the use of these terms in the Attachment.For Section 3.2 of the Attachment, should the wording be 'Operating Reserves are being used' or 'Operating Reserves can be used'? EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments
Duke Energy	No	(1) In the proposed Attachment 1, Duke Energy believes the criteria for calling an EEA1 should be covered under the BA's Emergency Operating Plan and that additional steps should be taken during EEA1 to prevent the BA from moving into the EEA2, such as calling for conservative operations, curtailment of ALL non-firm use of capacity resources except that retained as Contingency Reserve, and contacting the RC and impacted BAs/TOPs identified under the plan. In addition, we believe that taking some of the actions from EEA2 and moving them to EEA3 will make things more confusing for a System Operator to make the determination of what EEA level the entity is in. The proposed Attachment 1 places some of the actions taken under the currently effective EEA2 and just moves them to the proposed EEA3, muddying the water on how close a BA may

Organization	Yes or No	Question 5 Comment
		actually be to firm load shedding. Duke Energy believes clear separation should be maintained between the step of utilizing Contingency Reserves to meet firm load requirements, and the step where firm load shedding is imminent or in progress. Our interpretation is that utilizing your Contingency Reserve to meet firm load requirements is part of EEA2 and the shedding of firm load is part of EEA3 respectively. For example, a Balancing Authority (BA) that is maintaining 1000 MW of Contingency Reserves, along with having other measures it's capable of implementing upon use of such reserves (Emergency purchases, public appeals, voluntary load reductions of firm Commercial and Industrial customers,..), may be able to stay within the boundaries of an EEA2 and still maintain balance under BAL-001 without moving to EEA3.(2) Under the proposed Attachment 1, we believe that the required Operating Reserves should be changed to reference required Contingency Reserve, and as implemented to serve firm load, there should not be a requirement to shed load in order to maintain Contingency Reserves. (3) Under the NERC Functional Model, the Load Serving Entity (LSE) is responsible for managing its resource portfolio for meeting the demand and energy requirements of its End-use Customers. The LSE is responsible for coordinating its current-day, next-day, and seasonal operations with its Host Balancing Authority. To the extent that the LSE projects that it will be deficient in meeting its load requirements, the LSE is the entity responsible for working with Purchasing-Selling Entities to procure sufficient resources to address any deficiency. Among other activities under energy emergencies, the LSE communicates requests for voluntary load curtailment to its customers. At a minimum, Duke Energy believes that EOP-011 should retain the capability for the LSE to request the RC to call an EEA. Though EOP-011 and Attachment 1 may not have to be prescriptive in the activities expected of LSEs during an energy emergency, we believe that the responsibility of LSEs to procure additional resources as needed to address real-time deficiencies needs to be clearly understood and not be inadvertently moved to the Host BA by the changes proposed. (4) Based on our comments above, we suggest the following EEA levels

Organization	Yes or No	Question 5 Comment
		for consideration:1. EEA1 - All available resources in use to serve firm load, firm transactions, and required reserves.2. EEA2 - Utilization of Contingency Reserves and emergency assistance.3. EEA3 - Firm Load interruption is imminent or in progress.Further explanation is provided in our response to Question 7. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your concerns over the shedding of Load to maintain Operating Reserves. The SDT had industry support on the removing of the LSE from the Attachment and, therefore, has not returned it to the Attachment.
ACES Standards Collaborators	No	We are not supportive of shedding load to preserve Operating Reserves for an EEA 3 as presently included in Attachment 1, Section 3.2 of the standard. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
Associated Electric Cooperative, Inc. - JRO00088	No	See SERC OC Review Group comment
ISO/RTO Cojuncil Standards Review Committee	No	We are concerned with the added sentence that “In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement.” We do not agree that the deficient BA needs to shed firm load to meet the OR requirement. For so long as OR is still available, albeit depleted, a BA should be able to continue to utilize its OR to meet resource/demand/interchange balance. We do not support the idea of shedding firm load to avoid having to shed firm load when a resource contingency occurs or before the OR is fully utilized.Note that ERCOT does not support this comment. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.

Organization	Yes or No	Question 5 Comment
PacifiCorp	No	PacifiCorp disagrees with removing "Operating Reserves" from EEA 2 and adding it to EEA 3. For background, it is our understanding that when the Reliability Coordinator is communicating Energy Emergency Alerts (EEA) to Balancing Authorities, there is an orderly progression in resource deficiency for EEA 1, 2, and 3: Level 1 is characterized as all resources being in service, yet reserve requirements are continuing to be met; Level 2 is characterized by an erosion in the resource/load balance to the point that operating reserves are being impacted; and finally, Level 3 indicates that firm Load may no longer be able to be served. The Standard Drafting Team's proposal to move the inability to meet "Operating Reserves" characterization of system conditions into EEA 3 affects the orderly progression for EEA 1, EEA 2, and EEA 3.Proposed EEA 2 would involve deploying all resources except for contingency reserves, which would include deployment of Operating Reserves in excess of contingency reserves. However, proposed EEA 3 (supposedly more severe) states that Operating Reserves are maintained instead of deployed. This reverses the level of severity.The purpose of Operating Reserves is to be deployed to serve expected or unexpected swings in Load. When those swings occur, PacifiCorp deploys the Operating Reserves, up to the full amount available if necessary. The language in Attachment 1, Section 3.2 states that instead of deploying Operating Reserves to serve Load, entities would shed Load to serve our Operating Reserves. We find this unacceptable. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
Independent Electricity System Operator	No	We are indifferent with the proposed move of utilizing Operating Reserve (OR) from EEA 2 to EEA 3. However, we wonder if the result will be a greater # of EEA3 events. Also we are concerned with the added sentence that "In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement." We do not agree that the deficient BA needs to shed firm load to meet the OR requirement since OR is carried to guard against demand variations and contingencies resulting in loss of generating resource or import. For so long as OR is still available, albeit depleted, a BA should be able to continue to utilize its OR

Organization	Yes or No	Question 5 Comment
		to meet resource/demand/interchange balance. A BA should only shed load if a contingency occurs or when the OR is fully utilized and there still remains a resource/demand/interchange imbalance. In short, we do not support the idea of shedding firm load to avoid having to shed firm load when a resource contingency occurs or before the OR is fully utilized, unless such post-contingency actions are not quick enough to prevent instability or cascading due to loss of resource/import contingencies. Therefore, we suggest revising the last sentence in Section 3.2 of Attachment 1 to: "In this situation, the requesting BA must be able to shed firm Load if it is unable to meet resource/demand/interchange balance after fully utilizing its Operating Reserve. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
CenterPoint Energy Houston Electric, LLC	No	CenterPoint Energy does not disagree with the change regarding "Operating Reserves". However, CenterPoint Energy suggests the following revisions be made to Attachment 1-EOP-011-1 (Energy Emergency Alerts): Under Section B, EEA Levels, the Introduction paragraph speaks to establishing four levels of EEAs. CenterPoint Energy suggests changing this language to establishing three (3) levels of EEAs since there are only three levels used and described under Section B. Additionally, under Section B, 3. EEA 3, CenterPoint Energy does not feel that language in 3.5 (Returning to pre-Emergency conditions) should be included in the description for EEA 3. CenterPoint Energy suggests removing 3.5 and Alert 0 - Termination from the description of EEA 3 and adding a Section C which would include language described in 3.5 (Returning to pre-Emergency conditions) as well as Alert 0 - Termination. Furthermore, CenterPoint Energy suggest changing Alert 0 - Termination to just Termination. EOP SDT: SDT appreciates your comments has modified the number of levels to three, as suggested. The SDT believes it is important to maintain 3.5 and the Alert 0 language and has retained it in the current draft.

Organization	Yes or No	Question 5 Comment
MidAmerican Energy	No	MidAmerican is not supportive of shedding load to preserve Operating Reserves for an EEA 3 event as presently included in Attachment 1, Section 3.2 of the standard. MidAmerican believes that other actions can and should be taken prior to declaring EEA3 and / or shedding load just to maintain operating reserves. The revisions to EEA3 could lead to an inappropriate number of EEA3 events being called and possibly inappropriate load shedding. Any changes that could lead to inappropriate load shedding must be carefully considered. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
NV Energy	No	Traditionally, we have seen the EEA-1, -2, and -3 as an orderly progression in deficiency. Level 1 was characterized as all resources being in service, yet reserve requirements continuing to be met; Level 2 is characterized by an erosion in the resource/load balance to the point that operating reserves were being impacted; and finally, Level 3 indicates that firm Load may no longer be able to be served. The movment of “Operating Reserves” into EEA-3 seems to remove the distinction between EEA-1 and EEA-2 and makes an EEA-3 a significant step change in system condition from that of the EEA-2. The rationale for this change may be appropriate, and the change may be necessary; however, we are unable to find an explanation of the need for the change or what it is intended to accomplish. Also, we are concerned with the premise that the entity should shed some of its load in an EEA3 in order to maintain reserves. This appears to be contrary to our collective reliability goal of preserving service. Shedding the load for the sole purpose of retaining adequate reserves will unnecessarily deter from our reliability charge. Rather than shedding load pre-contingency, reliability is best served by continuing to serve the load and implementing load shed immediately following the contingency. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.

Organization	Yes or No	Question 5 Comment
Ameren	No	We believe that operating reserves should stay in EEA 2 until the conflict with operating reserves in BAL-002 is resolved. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
Tacoma Power	No	Attachment 1, EEA's 2 and 3 have been revised with respect to use of Operating Reserves. The Operating Reserve criteria have been removed from EEA 2, under EEA 3 is the following new requirement:3.2 Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement. It is unclear how this situation may or may not be applied to entities whom are a member of a reserve sharing group. While I believe I understand the intent of this requirement, it may lead to confusion or potential application of this requirement where it should not be applicable. I feel that further revisions are necessary to address Reserve Sharing Groups. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
The FRCC Operating Committee (Member Services)	Yes	
Colorado Springs Utilities	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	Dominion agrees with the change, but for additional clarity with an EEA3 (EEA 3-Inability to meet Operating Reserve requirement or Firm Load interruption is

Organization	Yes or No	Question 5 Comment
		imminent or in progress.) where you are NOT meeting Operating Reserves, Dominion suggests rewriting 3.2 to read as; Operating Reserves; such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement. EOP SDT: SDT appreciates your comments and believes it has modified the standard to reflect your comments.
Florida Municipal Power Agency	Yes	FMPA supports the comments submitted by FRCC.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	Yes	
Bonneville Power Administration	Yes	

Organization	Yes or No	Question 5 Comment
Wind Energy Transmission Texas, LLC	Yes	
Manitoba Hydro	Yes	
Oncor Electric Delivery LLC	Yes	
Idaho Power Co.	Yes	It keeps with the existing EEA1, EEA2 & EEA3 instead of interjecting an EEA4 in to the standard.
Texas Reliability Entity	Yes	
Wisconsin Electric	Yes	
Salt River Project	Yes	
Public Utility District No. 1 of Cowlitz County, WA		The District defers to BA comments.

6. **Do you agree with the VRFs and VSLs in EOP-011-1? If not, please indicate which Requirement(s) and specifically what you disagree with, and provide suggestions for improvement**

Summary Consideration: The EOP SDT appreciates the comments received from the industry. Time Horizon: The language of Requirements R1 and R2 require plans to be developed, maintained, and implemented. The EOP SDT believes that the current Time Horizons are correct, but "Long-term Planning" should be added. With the modification of Requirement R3, timeframe of 30 days, "Long-term" was not added.

Organization	Yes or No	Question 6 Comment
Northeast Power Coordinating Council	No	The Time Horizon for R1, R2 and R3 is currently Operations Planning. This should be Long-Term Planning. The definition of the two horizons are; Long-term Planning - a planning horizon of one year or longer. And Operations Planning - operating and resource plans from day-ahead up to and including seasonal. The EOP is developed for a period greater than a season.The condition "did not do so as soon as practical" in the HIGH VSL for R4 cannot be determined with any certainty or supported evidence. R4 itself need to be revised to provide the measurability to support compliance assessment. Please see the comment under Q7 regarding R4. We suggest revising the Medium VSL for R5 to Lower since failure to notify others that the alert has ended does not result in any unreliable operations. EOP SDT: Thank you for your comment. Time Horizon: The language of Requirements R1 and R2 says the plans are to be developed, maintained, and implemented. The EOP SDT believes that the current Time Horizons are correct, but "Long-term Planning" should be added. With the modification of R3 with a time frame of 30 days, Long-term was not added. R4: The VSLs were revised to comport with the revised language of the new time frame specified in the requirement.

Organization	Yes or No	Question 6 Comment
		R5: The EOPSDT concurs and has made the suggested revision.
Colorado Springs Utilities	No	1) R1 VSLs - How come the RC is approving a EOP that does not contain the required information?2) R1 VSLs - High VSL 2nd condition. If we fail to have a plan then we definitely failed to include 1.1 and 1.3. Think there is a typo.3) R3 VSLs - The RC should be responsible for verifying that EOPs have all the necessary parts before approval. This needs to be included in the VSLs for the RC under R3. EOP SDT: The SDT appreciates your comments. The SDT modified the VSL to remove the measure of the number of subparts and placed VSL measures on the plans; that it is reviewed, maintained and implemented.
SPP Standards Review Group	No	The 2nd part of the High VSL for Requirement R1 should read: 'The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include either Part 1.1 or Part 1.3.'Requirements R1 and R2 require the Transmission Operator and Balancing Authority to develop, maintain and implement an Emergency Operating Plan. The High VSLs for both R1 and R2 hold the responsible entity as non-compliant if the entity failed to maintain its Emergency Operating Plan yet nothing in the requirements or the supporting documentation provide any guidance on what needs to be done to satisfactorily 'maintain' the plan. The industry needs to know what is expected in order to demonstrate compliance with this requirement. Additionally, the use of the term'implement' in these requirements apparently has a different meaning than in other reliability standards. In other standards when a plan, process or procedure is to be implemented, it means that the plan, process or procedure is to be issued, be readily available for operator use, and for operators to be trained on the plan, process or procedure. In EOP-011-1, implement means the plan was activated due to an operating condition which requires initiation of the EOP. The drafting team needs to be consistent with other drafting teams such that confusion is minimized. We believe the drafting team can correct this inconsistency by adding two new requirements, one for the TOP and one for the BA, which requires the responsible entity to activate, or initiate, its plan when an Emergency condition

Organization	Yes or No	Question 6 Comment
		arises. For example, the drafting team is referred to EOP-005-2, R7 which requires the responsible entity to execute its restoration plan when a blackout occurs. In fact, EOP-005-2 is a good example of how to incorporate develop, maintain and implement into a reliability standard.The redline version of the 1st part of the Severe VSL for Requirement R2 is missing the following lead-in phrase: 'The Balancing Authority had a Reliability Coordinator-approved...'Change the 'Transmission Operator and Balancing Authority' language in the VSLs for Requirement R3 to 'Transmission Operator or Balancing Authority'. Also, the Reliability Coordinator is non-compliant in the Severe VSL for Requirement R3 if it fails to approve/disapprove a submitted Emergency Operating Plan within 60 days or if it fails to approve/disapprove the submitted plan at all. Why not combine the two parts into a single VSL which states: 'The Reliability Coordinator failed to approve or disapprove, with stated reasons for disapproval, a Transmission Operator or Balancing Authority submitted or revised Emergency Operating Plan within 60-calendar days.' Please add calendar to the 30, 40, 50, etc. and hyphenate. For example, 30-calendar days, 40-calendar days, 50-calendar days, etc.How does the drafting team propose to measure 'as soon as practical' in the High VSL for Requirement R4? Since no notification was made in the Severe VSL for Requirement R4, delete the redundant 'as soon as practical' phrase from the Severe VSL.Delete the 'has' in '...alert has ended.' at the end of the Moderate VSL for Requirement R5. The High VSL for Requirment R5 requires the Reliability Coordinator to conduct conference calls as necessary to communicate System conditions. This specific item has been pulled from Attachment 1 which is referenced in Requirement R5. It is not specifically listed in the requirement and is one of a mirade of items contained in Attachment 1. Why has the drafting team chosen this specific item to single out in the VSL and not include it in the requirement? The need for the emphasis is questioned especially in light of recent work in Project 2014-03 associated with IRO-014-3, R3 which is currently posted for industry comment and ballot. Requirement 5 will be redundant with IRO-014-3, R3 if it is approved. We suggest the drafting team rethink the need for this

Organization	Yes or No	Question 6 Comment
		emphasis and more closely coordinate with the TOP/IRO Revisions drafting team in Project 2014-03. EOP SDT: The SDT appreciates your comments. EOP SDT has chosen not to tell the industry "how" to maintain their plan; but as requested by the industry in past standards, entities should be allowed to determine how is best to maintain the plan. The EOP SDT used the same language found in the approved EOP-010, which speaks to "implement," and their intent is that to implement means to use the plan during an Emergency. The SDT modified the Requirement R3 language to avoid the issues with using day timeframes in the VSL. The rewritten Requirement R4 eliminates the term "as soon as practical," and the VSL reflects the new language. Requirement R5 was also modified based on your comments.
DTE Electric	No	The Severe VSL for R4 is semantically the same as the High VSL for R4. Suggest removing "as soon as practical" from the Severe VSL for R4. EOP SDT: The SDT appreciates your comments. The SDT modified the VSL to remove the language "as soon as practical."
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	No	The language in the proposed VSLs for R4 is unclear: High VSLThe Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority and did notify other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators, but did not do so as soon as practical.Severe VSLThe Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority and failed to notify, as soon as practical, other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators.We propose that the Severe VSL be revised to remove "as soon as practical". This will clarify the difference between the High VSL and Severe VSL. EOP SDT: The SDT appreciates your comments. The SDT modified the VSL to remove the language "as soon as practical."

Organization	Yes or No	Question 6 Comment
ACES Standards Collaborators	No	The VSL for R4 is ambiguous. How is an auditor or enforcement staff going to measure “as soon as practical?” This is a subjective measure and needs to be revised. One suggestion for improvement would be “without further delay.” EOP SDT: The SDT appreciates your comments. The SDT modified the VSL to remove the language “as soon as practical.”
ISO/RTO Cojuncil Standards Review Committee	No	A. The condition “did not do so as soon as practical” in the HIGH VSL for R4 cannot be determined with any certainty or supported evidence. R4 itself need to be revised to provide the measurability to support compliance assessment. Please see our comment under Q7.B. We suggest lowering the VSL for R5 from Medium to Low since failure to notify others that the alert has ended does not result in any unreliable operations. EOP SDT: The SDT appreciates your comments. The SDT modified the VSL to remove the language “as soon as practical.” The SDT agrees with your comment on Requirement R5 and has lowered the VSL.
Wind Energy Transmission Texas, LLC	No	The VSLs specifically state "The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan" and we don't agree with requiring the RC to approve company specific EOPs, therefore we cannot support the VSLs as written either. EOP SDT: The SDT appreciates your comments. The SDT modified the Requirement so the Reliability Coordinator no longer needs to “approve” the plan.
Independent Electricity System Operator	No	1. The condition “did not do so as soon as practical” in the HIGH VSL for R4 cannot be determined with any certainty or supported evidence. R4 itself need to be revised to provide the measurability to support compliance assessment. Please see our comment under Q7.2. We suggest moving the Medium VSL for R5 to Lower since failure to notify others that the alert has ended does not result in any unreliable operations

Organization	Yes or No	Question 6 Comment
		EOP SDT: The SDT appreciates your comments. The SDT modified the VSL to remove the language "as soon as practical." The SDT agrees with your comment on R5 and has lowered the VSL.
ReliabilityFirst	No	1. VSL for Requirement R1 - The second "OR" under the High VSL should not include the words "failed" in the first sentence fragment. ReliabilityFirst recommends the following for consideration: "The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but..."2. VSL for Requirement R5 - The VSLs for R5 all reference items in attachment 1 and not the actual requirement. RF recommends there be one Severe VSL which states: "The Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency Alert, as detailed in Attachment 1." EOP SDT: The SDT appreciates your comments. The SDT modified the VSL for Requirement R1. The SDT agrees with your comment on Requirement R5 and has modified the VSL.
CenterPoint Energy Houston Electric, LLC	No	For R1 and R2, all the listed violation scenarios are documentation issues, except for the 3rd scenario of the Severe VSL for these two requirements. CenterPoint Energy firmly believes there should be no High or Severe VSL for simply failing to document a process or procedure. High or Severe VSL's should only apply to egregious violations that had a tangible impact on the reliability of the BES. Thus, CenterPoint Energy recommends that R1 and R2's VSL's be revised to focus more on performance-based issues with the following language. Lower VSL: The Transmission Operator does not have documented Emergency Operating Procedures or Emergency Operating Processes to mitigate operating Emergencies on its Transmission System; or the Transmission Operator has documented Emergency Operating Procedures or Emergency Operating Processes to mitigate operating Emergencies on its Transmission System but failed to coordinate with its Reliability Coordinator Emergency Operating Plan; or the Transmission Operator had documented Emergency Operating Procedures or Emergency Operating Processes to mitigate

Organization	Yes or No	Question 6 Comment
		operating Emergencies on its Transmission System that were coordinated with its a Reliability Coordinator Emergency Operating but failed to include one or more of the sub-parts of R1 as applicable. Moderate VSL: The Transmission Operator had documented Emergency Operating Procedures or Emergency Operating Processes to mitigate operating Emergencies on its Transmission System that were coordinated with its Reliability Coordinator Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to implement one of the applicable sub-parts of R1 for an operating Emergency. High VSL: ...but failed to implement two of the applicable sub-parts of R1 for an operating Emergency. Severe VSL: ...but failed to implement three or more of the applicable sub-parts of R1 for an operating Emergency. **Response: Thank you for your comment.** EOP SDT: The SDT appreciates your comments. The SDT modified the VSL for Requirements R1 and R2 and removed the third scenario, and also the parts about document processes. The VSL is now based on the TOP or BA having, maintaining, implementing and getting the plan reviewed.
Public Utility District No. 1 of Cowlitz County, WA	No	R1 contains a typo in the High VSL column: “The Transmission Operator [failed to have] had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include either Part 1.1 or Part 1.3.” R3 has no provision other than untimely approval or disapproval. It appears in the instance the RC runs out of time to review, a simple stamp of approval on day 29 or 30 is sufficient for compliance. If the goal is to simply require the RC to issue approval or disapproval (without any quality control of the review), this then appears to extend a substantial amount of trust without verification. **Response: Thank you for your comment.** EOP SDT: The SDT appreciates your comments. The SDT modified the VSL for Requirement R1. The SDT agrees with your comment on Requirement R3 and has modified the VSL.

Organization	Yes or No	Question 6 Comment
Lincoln Electric System	No	The 2nd. part of the High VSL for Requirement R1 should read: "The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include either Part 1.1 or Part 1.3." Additionally, the 3rd part of the High VSLs for R1 and R2 indicate that an entity is non-compliant upon failure to maintain its Emergency Operating Plan. In consideration that R1 and R2 do not specify a maintenance cycle for the Emergency Operating Plan, how would this VSL be evaluated? As an example, an entity may decide to review their Plan on a two-year cycle but an auditor could view a maintenance cycle greater than once per calendar year as a failure to adequately maintain the Plan. To simplify the VSL, recommend removing the third part altogether. EOP SDT: The SDT appreciates your comments. The SDT modified the VSL for Requirements R1 and R2 and failure to maintain is now a moderate violation, but does not believe it should be removed.
Texas Reliability Entity	No	1)R1 High VSL appears to contain a copy/paste mistake in the second “OR” statement which states the TOP FAILED to have an RC approved EOP but goes on to say “but failed to include either Part 1.1 or Part 1.3.” Is the intent to capture that the TOP did have an approved RC plan “but failed to include either Part 1.1 or Part 1.3” rather than the TOP did not have a plan? The Severe VSL for R1 (second “OR” statement) covers the TOP failure to have an RC approved plan. Texas RE requests clarification from the SDT. 2) Texas RE recommends that R2 VSLs for all levels should specifically include the sub-parts of 2.4.1. Although it could be reasonably interpreted that the sub-parts of 2.4.1 are included, not explicitly stating they are included could pose issues in the enforcement realm (i.e., they would be unenforceable.) As currently written, a Registered Entity could include generating resources in its EOP without including those four sub parts (2.4.1.1.-2.4.1.4) and still be compliant. Texas RE recommends the EOP SDT add the phrase “including sub-parts of 2.4.1” immediately after “Sub-Parts 2.4.1.-2.4.9” in all the VSL levels.

Organization	Yes or No	Question 6 Comment
Ameren	No	We believe that R1 should be Medium. EOP SDT: The SDT appreciates your comments. The SDT modified the VSL for Requirement R1 but believes that the requirement has multiple severity levels, and those are reflected in the VSL.
Arizona Public Service Company	Yes	
MRO NERC Standards Review Forum	Yes	
Dominion	Yes	
SERC OC Review Group	Yes	
Duke Energy	Yes	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	
Associated Electric Cooperative, Inc. - JRO00088	Yes	

Organization	Yes or No	Question 6 Comment
Bonneville Power Administration	Yes	
Xcel Energy	Yes	
Manitoba Hydro	Yes	
MidAmerican Energy	Yes	
Oncor Electric Delivery LLC	Yes	
Idaho Power Co.	Yes	IPC Grid Operations Training does not believe administrative tasks should have a high VSL attached to it. **Response: Thank you for your comment.** EOP SDT: The SDT appreciates your comments. The SDT was unsure which of the tasks you were referencing as being administrative. The SDT did lower the maintenance of the plan to Moderate with this revision of the standard.
Wisconsin Electric	Yes	
Tacoma Power	Yes	
Salt River Project	Yes	

7. If you have any other comments on this Standard that you haven't already mentioned above, please provide them here

Summary Consideration: The EOP SDT has reviewed the comments in Question 7. The Standard was modified so that Load is not shed to maintain reserves. The SDT removed the requirement to have the Operating Plans approved by the Reliability Coordinator, and now are reviewed by the Reliability Coordinator for identification of any reliability risk with notification back to the BAs and TOPs. The term "System" was removed from the notification process in Requirements R1 and R2. The SDT modified the requirement so that it now states: "Management of Transmission and generation outages," as suggested by commenters. Timing requirements were added to the requirement to remove "as soon as practical." The term "Strategies" was replaced with "Processes" in Requirements R1 and R2. The SDT retained in the Standard the terms "potential" and "imminent" in Attachment 1 and the new Requirement R6 and believes these terms are appropriate. The SDT retained the reduction of internal utility energy; and if not applicable within a region, can be stated as such, but may be used in other regions. The SDT has replaced the term "requesting BA" in Attachment 1 with "energy deficient BA." The SDT made changes to the Standard, replacing "initiated" to "declared" where it is warranted. Voltage control was removed from the requirements, as suggested by commenters. The term "Emergency Operating Plan" was modified to "Operating Plan to mitigate Emergencies."

Organization	Question 7 Comment
ACES Standards Collaborators	(1) For Requirement R1, we recommend removing "strategies to prepare for" from parts 1.2 and 1.3. The elements of the Operating Plan should be processes or procedures to respond to an Emergency. As written, the Operating Plan will need to have both a strategy and a mitigation activity for each of the elements. How does one have a strategy and a mitigation activity for notifying the RC? Wouldn't that element be a process step? Parts 1.2 and 1.3 of this requirement need to be modified.(2) For Requirement R2, we recommend removing "strategies to prepare for" from parts 2.2 and 2.3. The elements of the Operating Plan should be processes or procedures to respond to an Emergency. As written, the Operating Plan will need to have both a strategy and a mitigation activity for each of the elements. How does one have a strategy and a mitigation activity

Organization	Question 7 Comment
	for notifying the RC? Wouldn't that element be a process step? Parts 2.2 and 2.3 of this requirement need to be modified.(3) For Requirement R4, we see no difference between the terms "as soon as practicable" and "as soon as practical." We strongly recommend revising this requirement with a reasonable measure of compliance. Also, as stated above, the VSL needs to be reworked, as the subjective measure of not notifying a BA or TOP as soon as practical results in a High violation severity level. This phrase is not appropriate for a reliability standard because it is ambiguous.(4) The term of "Operator-controlled manual Load shedding" should be a defined term. The word "operator" is not a defined term, although it could be assumed to refer to System Operators. There needs to be additional clarification on the intent of the drafting team.(5) There are still incomplete items on this project. The guidelines and technical basis should be included prior to ballot, not "to be added here after balloting." Without guidelines and technical basis for the drafting team's decisions, we cannot completely evaluate the standard, and therefore believe that more work is needed to improve the current draft.(6) Thank you for the opportunity to comment. Response: The EOP SDT has implemented the changes requested by ACES in Items 1, 2, and 3. The SDT does not believe that the term "Operated-controlled manual Load shedding" should be a defined term, as stated in Item 4. For Item 5, the guidelines and technical basis section of the standard is where the rationales from the requirements will be contained once the standard is approved; but during development of the standard, this information is placed in rationale boxes following each requirement.
MidAmerican Energy	: R1.2.3, Transmission is capitalized and generation is not, not sure if this is a type-o or not.R2.4.6, Customer fuel switching. The NSRF questions why this should be in an Emergency Operating Plan, since the customer will most likely be under 2.4.7, Demand response. As a BA, there are contracts with customers and if they elect to not be a signatory to those contracts, they always have the right to drop utility power and go on their owned and operated generation during the time of no utility power. Plus customers that own their own generation are excluded from the NERC Standards if they meet Exclusion E2 of the new BES definition. Recommend R2.4.6 be deleted from the R2. In addition to the above justification, there is no clear definition of "customer". Could a customer be

Organization	Question 7 Comment
	a single house hold that has a back up generator legally tied to their main circuit panel? This is another reason why R2.4.6 should be deleted. Response: The EOP SDT has modified the standard and believes it has incorporated your changes listed above by the deletion of 2.4.6.
Peak Reliability	1. Requirement 2.3: It is unclear whether this Requirement is for the BA to define criteria or simply reference criteria in Attachment 1. If the former, it appears inconsistent with the role of the RC in declaring EEAs. If the latter, it's unclear why this is necessary because the criteria already exists.2. Requirement 3:a. The Standard Drafting Team stated "While plan approval by the Reliability Coordinator is not specifically required by the directive in Order No. 693, the EOP SDT believes that approval by the Reliability Coordinator reduces risk to reliability of the BES." Please provide further clarity on the approval role of the RC. Several of the sub-requirements listed for BA R2, 2.4 are of such detail that the RC could not validate and therefore it is unclear how the RC would approve. Validation of R2.4 would be a Compliance Enforcement Authority function rather than an RC function.b. It appears there should there be a time delay after RC approval for each TOP/BA plan to be implemented in order to allow time for operators to be familiar with entity plans similar to the EOP-006-2 R6.3. If a BA is also a TOP, is only one Emergency Operating Plan required which cover all the requirements for both? Please clarify.4. There should be an annual review like there is for EOP-005/EOP-006. If annual or other scheduled periodic review and submittal becomes required, need verbiage on mutually agreeable schedule (reference EOP-005-2 R3). Response: The EOP SDT has implemented the changes to Requirement 2.3 to make it clear and not to have more criteria developed. The RC approval was removed from the standard. The EOP SDT does not believe that there needs to be a periodic review on the Operating Plan and has not included this requirement in the standard.
Independent Electricity System Operator	1. Requirement R4 is not measurable since there is no clear yardstick for "as soon as practical". While a time period may be subject to different views, we nevertheless suggest the SDT consider revising it to "shall notify, as soon as practical but no later than 5 minutes after receiving the notification," to put a bound on the time frame to support compliance assessment. 2. The wholesale replacement of "Energy Deficient Entity" with "Requesting BA" results in some

Organization	Question 7 Comment
	inconsistency with Condition (1) in the General Responsibility A.1 of Attachment 1, which indicates that a RC may initiated an EEA on its own request. Clearly, a RC will likely issue an EEA when it identifies a BA(s) in its RC Area is anticipating or experiencing energy deficiency. Nonetheless, the use of “Requesting BA” only in the rest of Attachment 1 fails to address the cases where a BA is energy deficient but it does not request its RC to initiate an EEA; rather, it’s the RC that initiates the EEA before being requested. We suggest the SDT to consider replacing “Requesting BA” with “Energy Deficient BA” or simply reinstate the phrase “Energy Deficient Entity”. Response: The EOP SDT has made the appropriate changes to the standard based on your comments.
Electric Reliability of Texas, Inc.	A. Load shedding to restore OR ERCOT does not support the paragraph 3.2 in Attachment 1 as currently drafted. There may be potential value in executing firm load shedding during periods when a region’s reserve levels have been compromised. However, the decision to take this operating action should rest solely with the system operator for the region based on its regional rules and real-time operational information. (SHOULD THIS BE THE BA, THE RC OR BOTH? - DO WE WANT TO COMMENT ON THE APPROPRIATE FUNCTIONAL ENTITY TO TAKE THIS ACTION?). Accordingly, ERCOT suggests that the relevant language be deleted from Attachment 1. Appropriate revisions are proposed below. Alternative Proposed Language - delete the relevant language altogether and leave it to the regions to decide whether and how to utilize firm load shedding in the maintenance of system reliability. 3.2 Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. It is likely that different regions will have different approaches to potential firm load shedding during emergency operations. Accordingly, the most effective way to address the issue in Attachment 1, paragraph 3.2, is to delete the language, thereby effectively allowing regions to manage the use of firm load shedding during emergency operations based on their regional rules, as reflected in their EOPs. B. Requirements based on "potential" or "imminent" operating conditions R5 and Attachment 1 EEA 3 section impose obligations based on "potential" and "imminent" operating conditions. These conditions are not defined based on any objective metrics, but rather apparently are triggered based solely on the subjective assessments of the relevant functional entity. This is potentially

Organization	Question 7 Comment
	problematic from a compliance and practical perspective. Because these triggering conditions for action under the relevant section of the standard are ambiguous, this will be problematic in CMEP activities because the auditor and registered entity may have different opinions as to what "potential" and "imminent" conditions are. Accordingly, based on its opinion of what constitutes "potential" or "imminent", the auditor may believe the registered entity should have acted under the relevant section of the standard, whereas based on its opinion, the registered may not have taken the relevant action because it did not believe the relevant conditions existed. This has the potential to create significant problems during CMEP reviews. From a practical perspective, to mitigate the potential for related compliance issues, the registered entity may be motivated to take conservative action under the standard to avoid violations. In other words, the entity may determine the "potential" or "imminent" condition exists, thereby tirggering the relevant operating action (e.g. initiating EEA under R5) when conditions do not warrant such action. This potential scenario and the associated problems are exacerbated by the fact that system conditions are dynamic and such conservative behavior will be triggered by different operating conditions all the time so there will be no definition or transparency as to what constitutes "potential" or "imminent" conditions. This is not only problematic from an operational perspective, but also from a markets perspective, because market participants will have no clear understanding of what triggers the relevant emergency actions w/r/t "potential" or "imminent" conditions. Conversely, the objective actual EEA thresholds do establish known, transparent system conditions that trigger the relevant emergency operational actions. Furthermore, those thresholds were developed to define emergency conditions and distinguish them from normal operations. Accordingly, there is no need to create ambiguous and vague emergency condition triggers based on "potential" and "imminent' conditions. The NERC rules should allow normal/market rules to support system operations until such time as the objective, specifically defined emergency conditions arise, which should be the trigger for the relevant emergency operations. C. RC approval of the TOP and BA emergency plans The proposed standard requires TOPs and BAs to have RC approved emergency plans, and, accordingly, requires the RC to approve/disapprove the relevant entities' plans. ERCOT does not support the RC approval requirement. The relevant FERC directives (PP 547 and 548 in Order 693) do not require this. FERC stated that the RC should be an applicable entity under the standard, finding that "...the Commission is persuaded that specific responsibilities for the reliability

Organization	Question 7 Comment
	coordinator in the development and coordination of emergency plans must be included as part of this Reliability Standard." (emphasis supplied). Thus, the Commission explicitly found that the role of the RC is to facilitate coordination in the development of other entities' plans. Thus, the proposed standard's RC approval requirement is not required by Order 693 and isn't necessary or appropriate. The RC should review and comment on the emergency plans of TOPs and BAs in their regions to foster coordinated, efficient and effective emergency operations, but they should not have approval authority. Imposing an approval requirement inappropriately inserts third party involvment in the actionable obligations of another entity, which raises practical as well as compliance issues. Accordingly, the RC approval requirement should be changed to a review and comment RC action. RequirementsR1.2.1 - Including the obligation to include system conditions in the notification is inappropriate. "System" is defined in terms of generation, transmission and distribution. How is the LSE or BA going to know system conditions, which, by definition includes transmission and distribution. And if it's an LSE, how will they know generation conditions? The notice should just be to inform the RC that it is in an Operating emergency. R1.2.3 - Rather than saying cancellation or recall, why not just say "Management of Transmission and generation outages"? Cancellation / recall seems too prescriptive and implies full cancellation or recall of an outage. Couldn't there be other options - e.g. partial recall? R2.4.1 - The items listed are not emergencies, which is how it reads. Rather they are considerations in mitigating emergencies. R2.4.4 - This implies that the BA has to research and be aware of all such programs. What if a program is missed or the BA is not aware of one? Why can't this be captured under public appeals? Also, what is a "necessary" energy reduction? Is it relative to the emergency shortfall or the number in the government program? 2.4.5 - What is reduction of internal utility energy use? Is it referring to energy reduction of the BA? if it is relative to third parties it is inappropriate. Even if it is relative to the BA at issue it is not appropriate. The plan should be related to external operational considerations. This should not be dictating internal entity business practices. 2.5 - Replace “Strategies” with “Policies” for coordinating EOPs.R4 - Should be revised to say "as soon as practical as determined by the RC" to make it measurable. The intent of the revision is to mitigate the ambiguity associated with the general "as soon as practical" timing requirement for the notice by defining it explicitly in terms of the RC determination to issue the notice when it is feasible/practical. This mitigates the potential for different subjective opinions on what this means

Organization	Question 7 Comment
	between the CEA and registered entity in the context of CMEP activities. Attachment 1 - Section B - Introduction - Delete the first part of the first sentence. It should just say there are four EEA levels. Also, the last sentence is unnecessary and confusing. EEA is an operating practice, just limited to emergencies. Delete the entire sentence. EEA 1 - Delete "and is concerned about sustaining its required Operating Reserves." This is ambiguous and creates potential audit problems. Make the trigger relative to an objective metric, which is achieved by the first part - i.e. all generation is committed. Response: The EOP SDT has reviewed your comments and made the following changes: The Standard was modified so that Load is not shed to maintain reserves. The SDT removed the requirement to have the Operating Plans approved by the Reliability Coordinator, they are now reviewed by the Reliability Coordinator. The term “System” was removed from the notification process in Requirements R1 and R2. The SDT modified the requirement so that is now states: “Management of Transmission and generation outages,” as suggested. Timing requirements were added to the requirement to remove “as soon as practical.” The term “Strategies” was replaced with “Processes” in Requirements R1 and R2. The SDT retained in the standard the terms “potential” and “imminent” in the Attachment 1 and the new Requirement R6 and believes these terms are appropriate. The SDT retained the reduction of internal utility energy; and if not applicable in your region, can be stated as so, but may be used in other regions. The SDT believes that the last sentences contained in EEA 1 are still valid.
ISO/RTO Cojuncil Standards Review Committee	A. We do not agree with the proposed revision to the definition for Energy Emergency. The phrase “has exhausted all other resource options” is unnecessary but begs the question on what are these other options. Further, since LSE is no longer referenced in any of the requirements and hence energy emergency conditions are now generally linked to a BA, the reference to LSE should also be removed. We therefore suggest the definition be revised to:Energy Emergency - A condition when a Balancing Authority can no longer meet its expected demand/resource/interchange obligations. B. Requirement R1: We propose the following revision to avoid ambiguity and to add clarity:1.1 Simply change it to Emergency Operating Plan roles and responsibilities since “activate and implement” are provided in the emergency operating plan itself.1.2 Replace “strategies” with “procedures” as the latter is more specific and can better facilitate compliance assessment1.2.7 We

Organization	Question 7 Comment
	do not see the need to specify “extreme weather conditions”. The TOP needs to mitigate adverse reliability impacts caused by any reasons - parallel flows, heaving loading caused by demand exceeding forecast, transmission facility forced outages, etc., not just extreme weather conditions. Suggest to remove 1.2.7 since this is already covered by the other parts.1.3 Suggest replacing “strategies” with “process” as the latter is more specific and can better facilitate compliance assessmentC. Requirement R2: We propose the following revision to avoid ambiguity and to add clarity:2.1 Simply change it to “Emergency Operating Plan roles and responsibilities” since “activate and implement” are provided in the emergency operating plan itself.2.4 Replace “strategies” with “procedures” as the latter is more specific and can better facilitate compliance assessment, and add the phrase “the following measures” to clarify that Parts 2.4.1 to 2.4.9 are the possible mitigating measures; and delete Part 2.4.9 since this is already covered by the other parts.2.5 Suggest replacing “strategies” with “process” as the latter is more specific and can better facilitate compliance assessmentD. Requirement R4 is not measurable since there is no clear yardstick for “as soon as practical”. While a time period may be subject to different views, we nevertheless suggest the SDT consider revising it to “shall notify, as soon as practical but no later than 5 minutes after receiving the notification unless conditions do not permit such communications,” to put a bound on the time frame to support compliance assessment. Note that ERCOT does not support this comment (above).E. The wholesale replacement of “Energy Deficient Entity” with “Requesting BA” results in some inconsistency with Condition (1) in the General Responsibility A.1 of Attachment 1, which indicates that an RC may initiate an EEA on its own request. Clearly, an RC will likely issue an EEA when it identifies that a BA(s) in its RC Area is anticipating or experiencing an energy deficiency. Nonetheless, the use of “Requesting BA” only in the rest of Attachment 1 fails to address the cases where a BA is energy deficient but it does not request its RC to initiate an EEA; rather, it’s the RC that initiates the EEA before being requested. We suggest that the SDT consider replacing “Requesting BA” with “Energy Deficient BA” or simply reinstate the phrase “Energy Deficient Entity”. We further suggest that “Energy Deficient BA” be defined within Attachment 1 by adding a sentence after the first sentence in the “Introduction” section as follows: “The BA who is experiencing an Energy Emergency is referred to as an “Energy Deficient BA.” EOP-011 R1.2 and R2.4 should include the phrase to ‘include the applicable elements’ and remove the phrase ‘at a minimum’. This would be consistent with the previous language contained in existing EOP-001 R4

Organization	Question 7 Comment
	and allow for solutions that do not exist or are not 'applicable' in certain areas.Also we are wondering about the word 'impact' in Part 1.2.7 and 2.4.9. Impact is not a measurable word to aid compliance assessment.F. The term Load-Serving Entity been deleted from R5 and Attachment 1 but it has not been deleted from the definition of "Energy Emergency." The term also continues to appear in the shaded area right below the definition of "Energy Emergency." We suggest deleting the term everywhere it appears.G. In the Purpose, R1, and 1.2.1, the word "operating" that appears before "Emergency" or "Emergencies" should be deleted, as it unnecessary. Same comment applies to VSLs for R1 (delete "operating" before "Emergencies" and before "Emergency").H. In 1.2.2, the word "control" should not be capitalized because "Voltage Control" is not a defined term.I. The word "and" should be deleted at the end of 1.2.7, if this part is retained (please see our comment under 7B, above. If the SDT's goal is to have 1.3 be at the same level as 1.2 then the "and" is not necessary.J. The SDT has indicated in the Rationale for R1 that "Emergency Operating Plan" is not a newly-defined term but that two defined terms ("Emergency" and "Operating Plan") are being used. Having the two terms used together creates a false assumption or expectation that "Emergency Operating Plan" is a defined term. We therefore suggest to either: Define the term "Emergency Operating Plan as: an Operating Plan that addresses Emergencies." , or,Revise the standard to replace "Emergency Operating Plan" with "Operating Plan for Emergencies".K. Compliance 1.1 - It is not necessary to repeat the definition of Compliance Enforcement Authority. A reference to the NERC Rules of Procedure is sufficient. The benefit is that, if the definition ever changes there, it will not have to be changed here. Therefore, 1.1 under Compliance should simply say: "Compliance Enforcement Authority" has the meaning ascribed to it in the NERC Rules of Procedure. L. For greater consistency, we suggest that the term "declare" be used throughout the Standard whenever Energy Emergency Alerts are discussed: (i) R5 - change "shall initiate an Energy Emergency Alert" to "shall declare an Energy Emergency Alert"; (ii) R5 Rationale: change "initiated" to "declared"; (iii) M5: change "initiated" to "declared" (also make corresponding changes in VSL section for R5); (iv) Attachment 1, A.1: change "Initiation by RC. An Energy Emergency Alert (EEA) may be initiated only by a RC" to "Declaration by RC. An Energy Emergency Alert (EEA) may be declared only by a RC."M. The drafting team should consider removing EOP-011 R4 since it is redundant to the following requirements: - IRO-015-1 R1 requires RC's to communicate notifications that impact neighboring RC's- EOP-002-4 R2 requires BA's to

Organization	Question 7 Comment
	communicate notifications that impact neighboring BA's- TOP-001-2 R5 requires TOP's to communicate notifications that impact neighboring TOP'sN. Attachment 1: - A. 1: Replace "RC's own request" with "RC's own initiative"- 2. Replace "reliability area" with "the RC Area"- Section B, Introduction: Suggest to remove the last sentence since it is unnecessary and confusing. EEA is an operating practice, just limited to emergencies. - EEA 1, Circumstances: Suggest to remove the last part "and is concerned about sustaining its required Operating Reserves." This part is ambiguous and may create audit problems; it makes trigger relative to an objective metric, which is already achieved by the first part. i.e. all generating resources are already committed.- EEA 2, Circumstances: We suggest delete "Requesting BA has implemented its approved Emergency Operations Plan." since declaring EEA (which has 4 levels) is part of the BA's Emergency Operating Plan per Requirement R2, which it is still implementing but not yet completed.- EEA 2, Section 2.4: Suggest to revise "return the Transmission element that may relieve" to "return any transmission elements that may relieve".- EEA 2 - Section 2.5: Suggest to revise the first sentence to "Before an EEA 3 is declared, the requesting BA...."- EEA 2, Section 2.5.1: The added language of "not being held for contingency reserves" is confusing (e.g. does it qualify peaking units, peaking and quick start or all gen) and does not appear to be needed. The sentence states that it only applies to generation that is "capable" of being on line. This implicitly excludes gen being held back for some other reason. Therefore, we suggest removing that last part "not being held for contingency reserves".- EEA 3, Section2.5.2: Suggest to delete "within provisions of any applicable agreements", which is potentially restricting and confusing because not all DSM is via agreements. It should simply states "Initiate all relevant DSM that is capable of being dispatched/utilized." Also, for reasons noted above, delete "not being held for contingency reserves". - EEA 3, Section 3.4: Should the TOP be TO, whose facility could be affected by the SOL/IROL reevaluation?- EEA 3, Section 3.4.1: This Section does not seem to be required since a BA is obligated to follow an RC's directive anyway.- EEA 3, Section 3.5.1: Suggest to clarify the role and sequence by replacing "that an alert has been downgraded" with "to downgrade the alert". Response: The EOP SDT has reviewed your comments and made the following changes: The term "Strategies" was replaced with Processes in Requirements R1 and R2. The SDT has removed the "as soon as practical" with a set time to make the requirement measureable. The SDT has replaced the term "requesting BA" in Attachment 1 with "energy deficient BA." The SDT made

Organization	Question 7 Comment
	changes to the standard replacing “initiated” to “declared” where they believe it was warranted. Voltage control was removed from the requirements, as suggested. The term “Emergency Operating Plan” was modified to “Operating Plan to mitigate Emergencies.” The SDT modified the EEA 2 Section 2.5.1 and EEA 3 Section 3.4, as suggested. The SDT retained in the standard the proposed definition. The SDT did not modify the Compliance Statement, this is used by NERC in its templates and is part of all standards.
Associated Electric Cooperative, Inc. - JRO00088	AECI Supports SERC OC Review Comments comments for Item 7, and provides the following additional comments for SDT consideration: FOR EOP-011-1: CONSIDER: AECI recommends that future EOP-011-1 postings conform with other NERC draft standard postings that position each requirement’s rationale box immediately preceding the corresponding requirement. RATIONALE: Not only does this help reviewers to check Measures against corresponding Requirements, it appears to be more consistent with NERC SDT’s normative practice. FOR EOP-011-1 R2 PARTS 2.4.2...2.4.8: CONSIDER subjugating parts 2.4.2 through 2.4.8, as parts 2.4.2.1 through 2.4.2.7, beneath a general 2.4.2 topic of “Load reduction resources” (AECI is not wed to this title). RATIONALE: a) Helps to clarify the nature of Public appeals”, unless the SDT is expecting that future public appeals might include their voluntarily adding energy resources for the grid, and b) because part 2.4.9 is substantively different from the preceding topics of Generating resources and Load reduction resources. FOR EOP-011-1 ATTACHMENT 1 PART 3.4: REPLACE: “of the TOP whose equipment” WITH: “of the TOP whose TO equipment” AND REPLACE: “by the TOP whose equipment” WITH: “by the TO whose equipment” RATIONALE: TOs actually own the equipment at risk, but TOPs would typically serve as the middle-man in these conversations, although they may at times have pre-determined formulas provided by the TO. Either way, this suggested language should work. Response: The EOP SDT has reviewed your comments and have inserted Transmission Owner, as suggested. The SDT considered modifying Requirement Part 2.4.2 as suggested, but retained the format as shown in the current draft believing both achieve the same intent in the standard.

Organization	Question 7 Comment
Puget Sound Energy	As defined in the NERC Glossary of Terms, the term “Emergency” is quite broad. As the standard is currently structured, an entity’s Emergency Operating Plan could be implemented regularly, with a resulting need to demonstrate compliance with the plan’s requirements during many events, regardless of the events’ potential to significantly impact the BES. To address this impact, the SDT could consider limiting the instances when an entity is required to implement the plan in some way - either by using other defined terms that include a measure of significance (for example, a combination of “Energy Emergency” and “Adverse Reliability Impact” (as that term was approved by the BOT on 08/04/2011) would reflect more significant events) or by listing the types of events that require implementation of the plan (instances of manual or automatic load shedding, entry into an energy emergency condition, etc.). EOP SDT Response: The SDT reviewed the comments and did not make any changes. The SDT believes that the proposed standard allows for the entity to determine when the conditions exists and is able to define them in the Operating Plan to mitigate Emergencies.
American Transmission Company LLC	ATC agrees with the SDT’s addition of the term “Operator-controlled” preceding the language “manual Load shedding” in Requirement R1, Sub-Requirement 1.2.6., however, ATC offers the following recommendations for added clarity and to further align the requirement to the rational given for Requirement R1.Currently Drafted Sub-Requirement from Standard EOP-011-1 (text below)1.2.6. Operator-controlled manual Load shedding plan coordinated to minimizethe use of automatic Load shedding;---ATC recommended revisions to Sub-Requirement R 1.2.6:(1) ATC recommends adding the text “Loads with” after “the use of” in Sub-Requirement 1.2.6. above. It would read as follows:R 1.2.6 “Operator-controlled manual Load shedding plan coordinated to minimize the use of Loads with automatic Load shedding”;(2) Alternatively, ATC recommends the following change be made to R1.2.6 where “use of” is replaced with “overlap with”. It would read as follows:R 1.2.6 “Operator-controlled manual Load shedding plan coordinated to minimize the overlap with automatic Load shedding;ATC believes either of these recommended revisions provides clarification regarding the SDT’s intent for Sub-Requirement 1.2.6, as defined in the Rationale for Requirement R1.

Organization	Question 7 Comment
	EOP SDT Response: The SDT reviewed the comments and made changes to these requirements. The SDT believes it has captured the intent of your recommendations.
CenterPoint Energy Houston Electric, LLC	CenterPoint Energy appreciates the efforts and the commitment of the SDT and the opportunity to provide the following additional comments: 1) CenterPoint Energy recommends that the phrase “for times when an Emergency has occurred” be added to M1 and M2 of EOP-011-1 draft 2, when referencing operator logs and voice recordings. This is to mirror EOP-011-1’s draft RSAW, where under the “Evidence Requested” section of R1 and R2, the guidance states “Evidence of activation, such as operator logs, voice recordings, or other communications, for times when an Emergency has occurred.” 2) If the SDT retains the RC-approval approach, CenterPoint Energy is concerned that the language in Requirement R1 restricts TOPs to one single Emergency Operating Plan. CenterPoint Energy believes that TOPs should be able to utilize multiple plans to address R1, as long as the plans in aggregate include all the required elements. Thus, R1 should be revised to state: “Each TOP shall develop, maintain, and implement one or more Reliability Coordinator-approved Emergency Operating Plan(s) to mitigate operating Emergencies on its Transmission System. At a minimum, the Emergency Operating Plan(s), in aggregate, shall include the following elements:”. 3) CenterPoint Energy believes R1 Part 1.1 is unnecessary. TOP-001-1a Requirement R1 states that TOPs have the responsibility and clear decision-making authority to take whatever actions necessary to ensure the reliability of its area and shall exercise specific authority to alleviate operating emergencies. TOP 001-1a R2 also states that, “Each Transmission Operator shall take immediate actions to alleviate operating emergencies including curtailing transmission service or energy schedules, operating equipment, shedding firm load, etc.” Further declaration of roles and responsibilities are unnecessary. CenterPoint Energy recommends R1 Part 1.1 be deleted. 4) CenterPoint Energy believes R1 Part 1.2.2 is duplicative of various existing requirements. TOP-004-2 R6 already requires TOPs to have policies and procedures that address monitoring and controlling of voltage levels that impact reliability. Additionally, VAR-001-3 R1 and R2 require TOPs to have sufficient reactive resources for Contingency conditions and to have formal policies and procedures for monitoring and controlling voltage levels “under normal and contingency conditions”. Furthermore, voltage control as proposed in the draft standard is not part of the currently effective EOP-001 Attachment 1, and so does need to be addressd within EOP-011. CenterPoint Energy believes Part 1.2.2 is unnecessary and should be deleted from EOP-011-1. 5) CenterPoint Energy

Organization	Question 7 Comment
	believes the "extreme weather conditions" referenced in R1 Part 1.2.7 is vague, and it would be challenging for TOPs and auditors to interpret what qualifies as "extreme". CenterPoint Energy believes that not all events of "extreme" weather result in emergency conditions requiring special mitigation strategies. In addition the Company believes that various existing operational planning requirements are sufficient to cover preparedness for extreme weather, such as TOP-005-2a R2 and Attachment 1 and TOP-006-2 R4. Therefore, Part 1.2.7 is unnecessary and should be deleted. If, however, an "extreme weather conditions" requirement must be retained, CenterPoint Energy recommends Part 1.2.7 be revised to state: "Mitigation of reliability impacts of extreme weather conditions defined by the Transmission Operator."6) CenterPoint Energy requests the SDT review the combined term "Transmission System". CenterPoint Energy believes the definition of transmission system is well understood; however, using the capitalized term "System" (a combination of generation, transmission, and distribution components.)introduces a conflict with the meaning of the defined term "Transmission". CenterPoint Energy recommends using the lower case term "system" in this instance. EOP SDT Response: The SDT reviewed the comments and added the suggested words to Measure M1 and M2. The RC approval approach was not retained and, therefore, this suggestion was not implemented. The SDT has retained the requirement on Roles and Responsibilities, it is important to understand who will be activating the Operating Plan to mitigate Emergencies. The SDT deleted Requirement Part R1.2.2, as suggested. The SDT retained the need for a process to be developed around extreme weather and did not make the suggested change. The SDT made the requested change by using the lower case term "system."
PPL NERC Registered Affiliates	Comment on Requirement 2, section 2.4.6 - We suggest the removal of "Customer Fuel Switching" from the list. It is unclear what a strategy titled "Customer Fuel Switching" would entail.Comment on Attachment A, section B.2.5 - The first sentence begins with "Before declaring an EEA 3, the requesting BA must..." This makes it sound as though the BA can declare an EEA 3. The sentence should read, "Before requesting an EEA 3, the BA must..."Comment on Attachment A, section B.2.1 - This section is preceded by the sentence, "During an EEA 2, RCs and BAs have the following responsibilities:" The first sentence of 2.1 states that, "The requesting BA shall communicate its needs to other BAs and market participants," but it does not describe how the BA is to make this

Organization	Question 7 Comment
	communication. It sounds as though this is a real time communication between the requesting BA and market participants (PSEs) but over what medium, and what obligation do the PSEs have to proactively look for communications from requesting BAs? Market participants (PSEs) may not have access to the RCIS website. Comment on Attachment A, section B.3.4.1 - The words “must agree that” in the first sentence of this section should be removed to reflect that the requesting BA does not have any options in the defining the prerequisites for SOL/IROL revision. We recommend the following change:”The requesting BA will, upon notification from its RC of the situation, take whatever actions are...”Comment on Attachment A, section B.2.5.1 - The mention of “all available generation units” is unnecessary as this is previously mentioned as a circumstance of an EEA1 in section B.1.Comment on Attachment A, section B.2 - Is this intended to mean that operating reserves should be maintained while the entity can’t meet the customer’s expected energy requirements? Operating reserves would not be maintained at the expense of cutting firm load. EOP SDT Response: The SDT reviewed the comments and has removed the “Customer Fuel Switching,” as requested.
Duke Energy	Energy Emergency Definition: Duke Energy suggests adding “or Balancing Responsibilities” at the end of the definition. As currently written, the definition suggests that a Balancing Authority carries Load Obligations which is not accurate. A Load Serving Entity does indeed have Load Obligations, but a Balancing Authority does not, and is only responsible for Balancing in its BA Area. Our suggested revision is as follows:Energy Emergency: A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its respective Load Obligations or Balancing responsibilities. R1 and R2 should not have “Reliability Coordinatorâ€approved” included in the requirement. (Please see comments associated with Question 3.)Below are Duke Energy’s suggested revisions to Attachment 1:Attachment 1 EOP-002-3.1/ EOP-011-1 modificationsEnergy Emergency AlertsIntroduction This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator (RC) to communicate the condition of a Balancing Authority (BA), which is experiencing an Energy Emergency.A. General Requirements 1. Initiation by Reliability Coordinator. An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator’s own request, or 2) upon the request of a BA or LSE.2. Notification. A Reliability Coordinator who declares an Energy

Organization	Question 7 Comment
	Emergency Alert shall notify all Balancing Authorities and Transmission Providers in its Reliability Area. The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between Reliability Coordinators shall be held as necessary to communicate system conditions. The RC shall notify the other RCs via RCIS, and the BAs and TOPs in its Reliability Area of any change in EEA level.B. Energy Emergency Alert LevelsIntroductionTo ensure that all Reliability Coordinators clearly understand potential and actual energy emergencies in the Interconnection, NERC has established four levels of Energy Emergency Alerts. The Reliability Coordinators will use these terms when explaining Energy Emergencies to each other. An Energy Emergency Alert is an emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC reliability standards or power supply contracts.The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.4. EEA 1- All available resources in use to serve firm load, firm transactions, and required reserves.Circumstances: The Requesting BA is experiencing conditions where all available resources are committed to meet firm load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves. During EEA 1, the Requesting BA has the following responsibilities to mitigate the energy emergency progressing to an EEA 2: o Implement its Emergency Operating Plan o Curtail non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) as needed to balance resources and demand. o Curtail non-firm end-use loads including Demand Side Management within the BA Area in accordance with applicable contracts (other than those designated to be shed to meet reserve requirements) as needed to balance resources and demand. o Implement conservative operations protocols within its BA Area to reduce risk of errors impacting resource availability.5. EEA 2 - Utilization of Contingency Reserves and emergency assistance.Circumstances: The Requesting BA is no longer able to balance its resources and the demand of firm loads and firm transactions without utilization of its Contingency Reserves.During EEA 2, the Requesting BA has the following responsibilities to mitigate the energy emergency progressing to an EEA 3: o Complete EEA 1 actions. o Curtail remaining non-firm wholesale energy sales. o Curtail remaining non-firm end-use loads including Demand Side Management within the BA Area in accordance with applicable contracts. o Implement use of Contingency Reserves to meet firm load obligations o Implement emergency

Organization	Question 7 Comment
	energy purchase transactions. o Issue public appeals to reduce demand o Request voltage reduction o Prepare to shed firm load2.2 Declaration period. The Requesting BA shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. During EEA 2, the RC has the following responsibilities to mitigate the energy emergency progressing to an EEA 3:2.3 Evaluating and mitigating Transmission limitations. The RC shall review Transmission outages and work with the TOP to see if it's possible to return the Transmission Element that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).3. EEA 3 - Firm Load interruption is imminent or in progress. Circumstances: The Requesting BA is, or projects that it will, no longer able to balance its resources and the demand of firm loads and firm transactions, and foresees a need for possible interruption of firm Load and firm transactions. During EEA 3, the RC and Requesting BA have the following responsibilities:3.1 Continue actions from EEA 2. The Reliability Coordinators and the Requesting BA shall continue to take all actions initiated during the EEA 2.3.2 Declaration Period. The Requesting BA shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. 3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the Requesting BA. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists or as allowed by the Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised: 3.4. Requesting BA obligations. The Requesting BA must agree that, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include load shedding. 3.5 Returning to pre-emergency conditions. Whenever energy is made available to a Requesting BA such that the transmission systems can be returned to their pre-emergency SOLs or IROLs condition, the Requesting BA shall request the Reliability Coordinator to downgrade the alert level. Alert 0 - Termination. When the Requesting BA is able to maintain its required reserves and balance its resources and demand, it shall request its RC to terminate the EEA.

Organization	Question 7 Comment
	The SDT reviewed your comments and appreciates your suggestions on modifications to Attachment 1. While not all recommendations were implemented, the EOP SDT did modify Attachment 1 substantially based on your submittals and those from the industry.
Exelon Companies	Exelon agrees with the majority of the substantive changes proposed but encourages the SDT to be as clear as possible with language in the Requirements when drafting the next revision. We note that by removing processes and procedures from R1 for example, and leaving only strategies, an entity may not be able to document the existence of a strategy to implement the Program. The RSAW, for example refers to an auditor verifying that procedures were implemented not that an entity had a strategy. We are generally uncomfortable with the language regarding evaluation of strategies and the use of “at a minimum”. We also note that the Time Horizon for R1 and R2 is Operations Planning (have a plan) and Real Time (implement elements of the plan / strategy). For those Requirements that are Real Time, we question the ability for some of them to be implemented. For example, the requirement to cancel transmission or generator outages in response to an Energy Emergency; the likelihood of bringing a generator or transmission line back into service from an outage in response to a real time emergency is very low. We would like the DT to consider whether this element belongs in an entities plan. We believe the more generic requirements in EOP-001-3 R2 can provide guidance in this area. Also, the requirement to mitigate extreme weather was subject to extensive review and determined not to require a standard. There is NERC Guidance addressing this. The SDT reviewed your comments and appreciates your suggestions on the RSAW and understands that the auditor should see if the plan has the process in place; and that during implementation of the plan, did the entity carry out the process if an Emergency dictated it. The SDT agrees that the success of the action in the plan such as calling for generation that is an outage, while not successful should not be the focus of the audit, but instead did you follow the process. The SDT agrees that there exists NERC guidance on extreme weather, but the SDT felt it is necessary that a process be in place so that an entity would address extreme weather in its company.
Florida Municipal Power Agency	FMPA supports the comments submitted by FRCC.

Organization	Question 7 Comment
Ameren	From our understanding there seems to be no mandated timeframe for what constitutes maintenance of TOP or BA emergency plans with respect to load shedding. We ask the drafting team; once the plan is approved by the RC, does the TOP or BA need to review or submit a plan every year, once every three years, or never? The SDT does not believe that a set timeframe needs to be established on maintenance, that the industry should be able to determine that based on the plan in which they have written to be in compliance to Requirements R1 and R2.
Xcel Energy	In section 3.2 of the Attachment 1, we believe the revised wording below provides additional clarity:3.2 Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. In this situation, the requesting BA must be [prepared] to shed an amount of firm Load in order to meet its Operating Reserve requirement. The SDT has removed 3.2 of Attachment 1.
PacifiCorp	PacifiCorp recommends the Standard Drafting Team replace the word “Strategies” with “A process” in R1.3 and R2.5 for coordinating Emergency Operating Plans with impacted Balancing Areas and Transmission Operators. PacifiCorp believes a process for Plan coordination, combined with evidence such as communication documentation, would provide improved compliance evidence, based on the Measures described in M1 and M2. The SDT has replaced “strategies” with “processes,” as recommended in Requirements R1 and R2. The SDT also eliminated Requirements R1.3 and R2.5 and placed the coordination on the Reliability Coordinator in Requirement R3.
The FRCC Operating Committee (Member Services)	R1 and R2 should not have “Reliability Coordinator-approved” included in the requirement. (Please see comments associated with Question 3.)R1.2.6 and R2.4.8. We agree with the rationale but would like additional language added to the standard to clarify the intent. Adding a “(UFLS and UVLS as applicable)” after automatic Load Shedding would be beneficial since the rationale box will not be included in the standard.Creating a new defined term would be preferred over the

Organization	Question 7 Comment
	combining of two separate defined terms (as noted in the Rationale for Requirement 1). It will add confusion to future readers when combined terms are used without specifically noting the combining of those terms. The SDT has removed from Requirements R1 and R2 the Reliability Coordinator-approved statement. The SDT did not believe it necessary to add UFLS and UVLS after Requirement Part R1.2.6 and Requirement Part R2.4.8 due to other changes made to those requirements. Where two defined terms were used side-by-side, the SDT tried to remove those occurrences to eliminate confusion.
JEA	R1&R2 should state that only "applicable" parts need to be included. Voltage control should not be part of the emergency plan and is already covered by standards TOP004-R6 and VAR001-3 R1. The SDT has made the modifications, as requested.
MRO NERC Standards Review Forum	R1.2.3, Transmission is capitalized and generation is not, not sure if this is a type-o or not. R2.4.6, Customer fuel switching. The NSRF questions why this should be in an Emergency Operating Plan, since the customer will most likely be under 2.4.7, Demand response. As a BA, there are contracts with customers and if they elect to not be a signatory to those contracts, they always have the right to drop utility power and go on their owned and operated generation during the time of no utility power. Plus customers that own their own generation are excluded from the NERC Standards if they meet Exclusion E2 of the new BES definition. Recommend R2.4.6 be deleted from the R2. In addition to the above justification, there is no clear definition of “customer”. Could a customer be a single house hold that has a back up generator legally tied to their main circuit panel? This is another reason why R2.4.6 should be deleted. The SDT removed Customer fuel switching from the standard.
DTE Electric	R1: The TOP should not be responsible for cancellation of generator outages. This function should remain being assigned to the BA. The current standard NERC EOP-002-3.1 has the BA postponing equipment maintenance.EEA2 Section 2.5.2: Demand-Side Management is a term defined in the

Organization	Question 7 Comment
	NERC glossary. Ensure the hypen is in place for both uses of the term.Attachment 1B Introduction, first sentence: change "four" to "three". The SDT appreciates your comment and understands that the TOP will not be the one responsible for the cancellation of the generation, but they do need a process in place if generation needs to be cancelled during a Transmission Emergency. The SDT has corrected the Demand-Side Management term in the document and modified the levels to three.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	R1: We appreciate the SDT's clarification of the term Emergency Operating Plan. The NERC Glossary defines Emergency as, "Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System." Southern continues to believe that the definition of Emergency as applied in EOP-011-1 is too broad. An emergency is considered as an operating condition which has not been studied and for which no mitigating plan has previously been developed. For example, having a contingency occur which was studied and for which a post-contingency mitigation plan has been developed, communicated, and can be implemented prior to an SOL exceedance is not an emergency even though it may require immediate manual action by an operator. Similarly, an IROL which can be mitigated prior to Tv as required by IRO-009 should not be considered an Emergency regardless of what actions the IRO-009-1, R1's Operating Process/Procedure/Plan requires. An Emergency Operating Plan, particularly as it relates to transmission and the TOP should be limited to multi-element contingencies due to things like weather, differential relay operations, relay failures, etc. or to other unstudied states where a potential or actual SOL exceedance needs to be managed as quickly as possible.In addition, Southern recognizes that R1 Rationale states that the Transmission Operator can note R1 Parts are "not applicable" in their plan. However, Southern requests that the SDT add that verbiage in the requirement (R1) rather than relying on rationale boxes that are deleted in final versions of the standards or other supporting documents:"Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System. At a minimum, if applicable, the Emergency Operating Plan shall include the following elements:" Southern requests more guidance on the elements listed in R1.2. Are the strategies listed unique to emergency operations? For example, is the

Organization	Question 7 Comment
	Voltage control listed that which is unique to an emergency or also a part of normal voltage control procedures? If these strategies are unique to an emergency, Southern suggests that the SDT add more clarity by removing the sub-bullets and revising the requirement to state:"R1.2. Strategies that are not included in normal operating procedures that are used to prepare for and mitigate Emergencies; " R1.2.6. Southern believes this requirement needs additional clarity by removing coordinated as revised:"Operator-controlled manual Load shedding plan designed to minimize the use of loads that are a part of automatic Load shedding plans;"R2: Southern also believes "if applicable" should be included in the Balancing Authority's Capacity and Energy Emergency Plans as stated in the draft RSAW. If this designation is significant enough to include in the RSAW then it should be stated in the requirement. (see similar comment for R1 above)R2.3 Southern suggests modifying this requirement to be consistent with R5 and Attachment 1 language where a BA requests their RC to initiate an EEA rather than the BA declare an EEA. Southern suggests the following revision: " Criteria to request an Energy Emergency Alert, per Attachment 1;"R2.4.1 Southern suggests adding "if applicable" to this requirement because a BA may not be the sole function that has knowledge of all information listed in the sub-bullets for R2.4.1.R2.4.2, R2.4.3, R2.4.4: Southern requests the SDT to provide guidance on each of these strategies. Are these specific to certain regions or customers and not continent wide? For example, what is the difference between a Voluntary Load reduction and a Public Appeal? Southern requests the SDT to provide examples. R4: Southern would like to see more guidance on determining what "impacted" means since it can be a subjective term and therefore makes the requirement less measureable. In R4, Att. 1 section 2.3, Att. 1 section 3.3, Att. 1 section 3.5.1, and Att. 1 section 0.1, the wording inappropriately intertwines notification/communication from an RC to BAs and TOPs in a manner contrary to current, and in fact very reliable, practices used today . In these locations, the terminology "other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators" or similar words are used. In practice, based on the established hierarchy of RCs and their associated BAs/TOPs, an RC will notify and communicate with other RC's and with the BAs and TOPs in it RC Area. To require an RC to notify/communicate with a non-associated "impacted" BA/TOP as the current draft's wording implies has the potential to cause confusion and is not a relationship which operators are accustom to. BAs/TOPs should be expected to communicate with one and only one RC to maintain the "command and control" hierarchy that is currently used and,

Organization	Question 7 Comment
	in our opinion, is expected by FERC.We suggest alternate wording for “other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators” or similar references to clearly maintain the established RC to BA/TOP communication hierarchy:An RC will notify “impacted Balancing Authorities and Transmission Operators in their own RC Area as well as other impacted Reliability Coordinators who are expected to notify impacted Balancing Authorities and Transmission Operators in their RC Area”Attachment 1 Section 2.3 - Southern suggests the following revision to limit the scope of BA responsibilities to contact requesting BAs and to clarify the appropriate communications channels :” A neighboring BA with available resources and that has contractural agreements in place with a requesting BA shall coordinate with it’s RC as appropriate to provide assistance to the requesting BA.”Attachment 1 Section 2.5 Southern suggests that the title “BA actions” be updated to reflect “Requesting BA actions” to reference the appropriate BA. Southern also suggests that the word choice be updated to reflect that a BA can not declare an EEA as indicated the Initiation Section of Attachment 1 and EOP-011-1 R5.Attachment 1 Section 2.5.2 - Southern asks the SDT to consider replacing “curtailed” with “activated” to improve word choice and add clarity. The use of “curtailed” when referring to DSM can be very confusing.Attachment 1 Section 3.2 - Southern requests for the SDT to consider modifying this language because some BAs may not participate in an Operating Reserve sharing program, and to explicity state that it is not required to shed Load to maintain normal Operating Reserves during this abnormal situation. Southern believes that the following revision should be made to add guidance:”Operating Reserves. Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through an Operating Reserve sharing program, if applicable. In this situation, the requesting BA must be able to, but not required to pre-contingency, shed an amount of firm Load in order to meet its Operating Reserve requirement. A BA may continue to carry reserves below the required minimum and plan to shed Load post contingency. EOP SDT Response: The SDT appreciates your comments and we have added to Requirements R1 and R2 “as applicable.” The SDT did not include the suggested language for Requirement Part R1.2 and Requirement Part 2.4, it believes that it is clear as written that this is for emergency situations and not during normal events. The SDT modified the Load shedding requirement based on industry comments and removed the term “coordinated.” The term “criteria” was removed from

Organization	Question 7 Comment
	Requirement Part 2.3 and was made consistent with Requirement R5 and the Attachment. Since "If applicable" was added to Requirement R2, the SDT did not believe it needed to be added to those items in the requirement parts. The SDT appreciates the comments on "impacted" and has modified Requirement R4, which, in the new draft, is Requirement R5, such that the Reliability Coordinator is notifying its Balancing Authorities and Transmission Operators and neighboring Reliability Coordinators, thus removing the term "impacted." The SDT modified in Attachment 1, Requirement Part 2.3 such that the Reliability Coordinators are sharing information and having the appropriate Balancing Authorities work together, as needed. In Attachment 1, 2.5 and 2.5.2 were modified, as requested. In Attachment 1, 3.2 was deleted.
SERC OC Review Group	R2 - For consistency with Part 1.1, remove 'and implement' from 2.1 (this is not struck on the redlined version, but it does show that it has been removed on the clean version).R2 - For consistency with R1, the content of 2.2 and 2.3 should be moved as sub parts below 2.4 instead of included as "stand alone" parts 2.2 and 2.3.R2- The requirement appears to use a newly capitalized term "Capacity". This term is not included in the NERC Glossary of Terms currently posted. If the intent is to use the existing defined terms, Capacity Emergency and Energy Emergency, then the SDT needs to write the requirement accordingly. Attachment 1 Section A1 - review wording of item 2 for redundant use of 'request'.Attachment 1 Section 3.4 - SDT should consider that Transmission Owner is more appropriate than Transmission Operator for the subject review of SOLs and IROLs. The comments expressed herein represent a consensus of the views of theabove named members of the SERC OC Review Group only and should not beconstrued as the position of the SERC Reliability Corporation, or its board or itsofficers. EOP SDT Response: The SDT appreciates your comments and has modified the standard to remove the term "implement." The SDT has redrafted Requirement R2 and we believe we have captured your requested changes. We have included the Transmission Owner in Attachment 1, as requested, and reworded Item 2 to remove the redundant use of "request."
Dominion	R2 - For consistency with Part 1.1; remove 'and implement' from 2.1 (this is not struck on the redlined version, but it does show that it has been removed on the clean version).R2 - For consistency with R1; the content of 2.2 and 2.3 should be moved as sub parts below 2.4 instead of

Organization	Question 7 Comment
	included as “stand alone” parts 2.2 and 2.3.R2- The requirement appears to use a newly capitalized term “Capacity”. This term is not included in the NERC Glossary of Terms currently posted. If the intent is to use the existing defined terms, Capacity Emergency and Energy Emergency, then the SDT needs to write the requirement accordingly. EOP SDT Response: The SDT appreciates your comments and has modified the standard to remove the term “implement.” The SDT has redrafted Requirement R2 and we believe we have captured your requested changes. We have included the Transmission Owner in Attachment 1, as requested, and reworded Item 2 to remove the redundant use of “request.”
Tacoma Power	R2.3 needs to be revised to state “Criteria to request declaration of an Energy Emergency Alert per Attachment 1” EOP SDT Response: The SDT appreciates your comments and has modified Requirement Part R2.3.
ReliabilityFirst	ReliabilityFirst submits the following comments for consideration:1. Requirement R4 - ReliabilityFirst believes the term “as soon as practical” is ambiguous, does not provide any added value, and should not be used in standards. This term leaves the requirement open to interpretation and potential problems in compliance monitoring and enforcement. ReliabilityFirst recommends the following for consideration “Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify the impacted Reliability Coordinators, Balancing Authorities and Transmission Operators[, within 30 minutes of the start of the Emergency.]” This time frame of 30 minutes is used throughout similar standards and we believe it is applicable here as well. 2. Requirement R7 - ReliabilityFirst believes the term “as soon as practical is ambiguous, does not provide any added value, and should not be used in standards. This term leaves the requirement open to interpretation and potential problems in compliance monitoring and enforcement. ReliabilityFirst recommends the following for consideration “Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify the impacted Reliability Coordinators, Balancing Authorities and Transmission Operators[, within 30 minutes of the start of the Emergency.]” This time frame of 30 minutes is used throughout similar standards and we believe it is applicable here as well3. Requirement R9 - ReliabilityFirst believes there should a timeframe

Organization	Question 7 Comment
	associated with how long a Reliability Coordinator has to initiate a NERC Energy Emergency Alert following a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency. ReliabilityFirst recommends the following for consideration: "Each Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall initiate a NERC Energy Emergency Alert, as detailed in Attachment 1[, within 30 minutes of request.]" This time frame of 30 minutes is used throughout similar standards and we believe it is applicable here as well EOP SDT Response: The SDT appreciates your comments and has modified the standard and removed the term "as soon as practical" and set defined times. The SDT does not believe that the now drafted Requirement R6 should have a set time since the notification timeframe is being handled in Requirement R5.
Seattle City Light	Seattle offers the following suggestions:For R1.2.1 "Notification to the RC to include current and projected System conditions when experiencing an operating Emergency": to keep the focus on reliability and minimize compliance traps, please add language about notifications such as 'as soon as practical.' The focus during an emergency should be on addressing the emergency, not on ensuring compliance activities. To date, auditors at times have focused on the exact timing of notifications while appearing to neglect the larger picture. Additional wording may help avoid such interpretations.For R1.2.2 Voltage Control, please clarify. In the current version of EOP-001 (specifically Attachment EOP-001-0b) voltage control is mentioned in 'Load Management' as voltage reductions. The new standard doesn't give any direction. The 'Rationale for Requirement' states: "Requirement R1 Part 1.2. was added to this standard for the Transmission Operator to address strategies to prepare for and mitigate Emergencies using voltage control methods, which could include switching of capacitor and reactor banks, generator reactive output, and the use of synchronous condensers." As such this subrequirement seems like this is a new requirement - not a consolidation of the old requirements.For R1.2.6 and R2.4.8, "Operator-controlled manual Load shedding plan coordinated to minimize the use of automatic Load shedding": Please provide guidance in this subrequirement or the RSAW as to how such "coordination to minimize" would be evidenced and audited. Alternatively, reword the subrequirement to provide more specificity as to what is intended here. Without additional guidance, this seemingly minor subrequirement could

Organization	Question 7 Comment
	require more evidence than all the other subrequirements together while adding minimal BES reliability benefit.Regarding R1.3 "Strategies for coordinating Emergency Operating Plans with impacted TOPs and BAs" is excessively vague for a world-class Standard. Please provide additional guidance as to what is expected or delete as unecessary. Is an "annual exchange of plans" among impacted TOPs and BAs such a "strategy" or is something further anticipated? As written the subrequirement is reminiscent of a "version 0" best practice: it does not require anything other than that the plan list one or more strategies. It does not require that the strategies be implemented or followed, nor that they are effective or comprehensive strategies. If such activities and characteristics are deemed necessary for BES reliability then they should be required explicitly; if they are not necessary then the subrequirement should be dropped entirely. Standards are not the place for "nice to have" items. In the absence of additional information, Seattle recommends that R1.3 be deleted. The subrequirements of R2.4 for BAs are similarly vague and likewise should be clarified or deleted. EOP SDT Response: The SDT appreciates your comments but based on industry input, the term “as soon as practical,” will not be added to Requirement Part R1.2.1. The SDT has removed the need for Voltage Control in the standard. The SDT has modified Requirement Part R1.2.6 and Requirement Part R2.4.8 based on industry comments. Requirement Part R1.3 and Requirement Part R2.4 have been deleted.
SPP Standards Review Group	Shouldn’t the term “energy emergency” as it appears in the 5th line of the Rationale Box for its definition be capitalized?Also in the Rationale Box for the definition under IRO-005-3.1a, the SDT states that IRO-005-3.1a is being revised under Project 2014-03 TOP/IRO Revisions. This is not the case. Project 2014-03 is not working with IRO-005. The IRO Five Year Review Team moved requirements regarding notification from IRO-005-3.1a to IRO-008-1 and recommended retiring IRO-005. Project 2014-03 has made additional changes to IRO-008-1 but the changes proposed by the IRO Five Year Review Team have been incorporated into the latest revision of IRO-008-2 by Project 2014-03. The term energy emergency is not in either version of IRO-008. (This same comment applies to a similar section in the Proposed Definitions for the NERC Glossary of Terms document.)Terms such as 30-calendar days should be hyphenated.How does the drafting team propose to measure ‘as soon as practical’ in Requirement R4?The following comments are directed

Organization	Question 7 Comment
	toward Attachment 1.Changing the 'should' to 'shall' in the sentence in Section A.2 creates a conflict in that the Reliability Coordinator is now required to hold conference calls but the conditions under which those calls are to be held are not specifically defined by the phrase 'as necessary.' We recommend the drafting team return the language to the original language or provide the Reliability Coordinator with a list of conditions which would necessitate such calls. Also, see our comment in response to Question 6 regarding additional information on this issue.In the 5th line of the Introduction under Section B. EEA Levels, change 'standard' to 'standards'.Insert an 'an' between 'During' and 'EEA2' in the line between the last bullet under Circumstances under Section B.2 and 2.1.Insert 'to service' between the 'return' and the 'the' at the end of the 2nd line of B.2.4.Insert an 'an' between 'During' and 'EEA 3' in the line between the bullet under Circumstances under Section B.3 and 3.1.See our comment on 3.2 in Question 5 above.Add RCs to B.3.3 to be consistent with B.2.2.Replace 'SOLs or IROLs' with 'SOL or IROL' in the 3rd line of B.3.5.The following comments are directed toward the Technical Justification document.The designation for footnote 4 should be a superscript in the next to last line on Page 3.The 2nd and 3rd bullets under EOP-002-2 are actually a continuation of the 1st bullet. The bullets, not the text, need to be deleted. EOP SDT Response: The SDT appreciates your comments and has removed the term "as soon as practical."
Texas Reliability Entity	Texas RE recognizes the amount of work the SDT has put into this standard and applauds the team for successfully combining the existing Emergency Operations requirements into one single Standard. Much of the ambiguity has been eliminated and various inputs have been addressed well. However, Texas RE has a few concerns with the current draft which prompt a negative vote at this time. 1) The main focus of this standard appears to be energy and capacity emergencies. Are there other types of emergencies that need to be covered by emergency plans? For example, does the standard need to cover requirements if a TOP may need to declare a Transmission emergency if it is unable to mitigate an IROL or SOL violation?2) Requirements R1 and R2: EOPs are critical to the reliability of the BES and assurance that the plans are maintained is necessary. The mapping document on the 2009-03 project page shows that the requirement for a time based review/update of EOPs (from EOP-001-2.2.1b, Requirement R5) has been translated to EOP-001-1,

Organization	Question 7 Comment
	Requirement R1. However, the draft standard does not include a requirement for a TOP or BA to review/revise their EOPs on a specified periodicity. Therefore it is not measurable. Texas RE recommends the EOP SDT adding the following phrase to both R1.4 and R2.6: “Revise and review the EOP as needed but no less than annually.”3) The language for Requirements R1.2.6 and R2.4.8 states that operator-controlled Load shedding shall be coordinated to minimize the use of Automatic Load Shedding. That language is not in synch with the Rationale for Requirement R1 which states the goal is minimize the manual use of Loads armed for automatic Load shedding; recognizing that complete exclusion may not be possible. Texas RE recommends the EOP SDT revise the language in Requirements R1.2.6 and R2.4.8 to the following: “Operator-controlled manual Load shedding plan coordinated to minimize the use of Loads armed for automatic Load shedding;”4) Requirement R4: While agreeing with the change of practicable to practical in the requirement, Texas RE asserts that omitting a required notification “not to exceed” date allows a potential reliability gap. RCs, BAs, and TOPs need to know that Emergency notifications have taken place even if they were not directly involved in the Emergency, and they need to know relatively quickly. This communication can be assured by the addition of “but no later than seven days after the end of the Emergency” after “as soon as practical”. The addition would require a corresponding adjustment to the VSL.In addition, the Rationale for R4 states that it was an existing requirement in EOP-002-3.1 for BAs. It appears that the EOP-002-3.1 requirement being referenced here is Requirement R3, which required a BA experiencing an operating capacity or energy emergency to communicate system conditions to its RC and neighboring BAs. The requirement did not restrict the required communication to “impacted” BAs. Texas RE recommends the EOP SDT consider removal of the phrase “other impacted” RCs, BAs and TOPs and replace it with “neighboring” RCs, BAs and TOPs. Replacing “impacted” by “neighboring” is important since, among other reasons, the Emergency may have been resolved efficiently in that instance, but conditions may still exist for the Emergency to reoccur and the potential next Emergency may involve more TOPs and BAs than the previous Emergency. 5) Requirement R5: R5 states that an RC shall initiate an Energy Emergency Alert (EEA) when a BA in its area has a potential or actual Energy Emergency but does not address the RC responsibility in the event the BA has a Capacity Emergency. Requirement R2.2 requires that a BA having a Capacity Emergency notify the RC of that

Organization	Question 7 Comment
	Emergency. Texas RE requests clarification regarding the RC responsibility to take some action in the event of a BA Capacity Emergency. EOP SDT Response: The SDT appreciates your comments and discussed the need for some type of time requirement for review, but believes that the industry should determine how often they need to maintain their plan based on the processes included in the plan. The SDT revised Requirement Part 1.2.6 and Requirement Part 2.4.8 based on industry comment, and reflects your requested changes. The SDT modified Requirement R4 and has removed the term “impacted” and added “neighboring.” The SDT believes Attachment 1 defines the needed criteria in which to implement the levels of and Energy Emergency Alert.
Public Utility District No. 1 of Cowlitz County, WA	The District feels the SDT is progressing in the correct direction. However, concerning the changes made to Requirement R4, the District recommends the SDT review word usage of “practical” as it can be easily misunderstood. Its usage in “as soon as practical” is equivalent to “as soon as useful.” If this is the intent of the SDT, the District recommends “as soon as useful” due to the fact that “practical” is often confused with “practicable,” i.e., as soon as possible. The District appreciates the desire not to engulf BAs and TOPs with excessive or nuisance Emergency notices. EOP SDT Response: The SDT appreciates your comments and has removed the language “as soon as practical.”
Northeast Power Coordinating Council	The Drafting Team should revise the Evidence Retention section of this standard which is very specific requiring the retention of all versions of the EOP within the audit period. This is inconsistent with the allowed practice of maintaining detailed revision history within the current version. With the possible use of RAI to extend audit cycles (which could increase the time between TOP audits to more than 3 years), TOP and BA’s will be maintaining versions of EOP solely for backward horizon compliance monitoring. A more effective approach is to require the TOP and BA to retain the current version with revision history and utilize spot checking to monitor compliance. The wholesale replacement of “Energy Deficient Entity” with “Requesting BA” results in some inconsistency with Condition (1) in the General Responsibility A.1 of Attachment 1, which indicates

Organization	Question 7 Comment
	that a RC may initiate an EEA on its own request. Clearly, a RC will likely issue an EEA when it identifies a BA(s) in its RC Area is anticipating or experiencing energy deficiency. Nonetheless, the use of “Requesting BA” only in the rest of Attachment 1 fails to address the cases where a BA is energy deficient but it does not request its RC to initiate an EEA; rather, it is the RC that initiates the EEA before being requested. We suggest the SDT to consider replacing “Requesting BA” with “Energy Deficient BA” or simply reinstate the phrase “Energy Deficient Entity”.EOP-011-1 Parts 1.2 and 2.4 should retain the phrase to ‘include the applicable elements’ below, and remove the phrase ‘at a minimum’. This would be consistent with the previous language contained in existing EOP-001 R4 and allow for solutions that do not exist or are not ‘applicable’ in certain areas.Is “impact” a measurable word that should be in the standard? In sub-Part 1.2 and Part 2.5 the TOP and BA are required to coordinate with impacted TOP and impacted BA. Impacted could mean electrically affected by the EOP or it could mean having a role to play in executing the EOP. In R4 the ambiguity in impact is similar. Guidance or clarity is needed around this term.R2 - For consistency with Part 1.1 remove ‘and implement’ from Part 2.1 (this is not struck on the redlined version, but it does show that it has been removed on the clean version).R2 - For consistency with R1; the content of Parts 2.2 and 2.3 should be moved as sub-Parts below Part 2.4 instead of included as standalone Parts 2.2 and 2.3.R2- The requirement appears to use a newly capitalized term “Capacity”. This term is not included in the NERC Glossary of Terms currently posted. If the intent is to use the existing defined terms, Capacity Emergency and Energy Emergency, then the SDT needs to write the requirement accordingly. Regarding requirement R4, first, requirement R4 is not measurable since there is no clear yardstick for “as soon as practical”. This concept was a challenge in the development of FAC-003-3. In FAC-003-3 the phrase “without any intentional time delay” was used, or consider adding language similar to TOP-001-2 requirement R5 that uses the phrase “unless conditions do not permit such communications.” Secondly, the Drafting Team should consider removing EOPâ€011 R4 since it is redundant to the following requirements:- IRO-015-1 R1 requires RC’s to communicate notifications that impact neighboring RC’s- EOP-002-4 R2 requires BA’s to communicate notifications that impact neighboring BA’s- TOP-001-2 R5 requires TOP’s to communicate notifications that impact neighboring TOP’sFinally, the draft IRO-014 R3 may introduce double jeopardy for non-compliance. The SDT should coordinate with the Project 2014-03 Revisions to TOP and IRO Standards Drafting Team IRO-014-3 requirement R3 and EOP-011-1

Organization	Question 7 Comment
	requirement R4. Those two requirements are very similar. It could argued that receiving a notification of an Emergency results in the RC identifying an actual emergency and then both EOP-011-1 and IRO-14-3 require the RC to notify other RC's. EOP-011-1 then goes further and requires the RC to notify other TOPs and BAs. The notification to other RCs is covered by these two Standards. This double jeopardy needs to be addressed. EOP SDT Response: The SDT appreciates your comments. The SDT reviewed the areas where the terms requesting BA was used and replaced it with "energy deficient BA" in the appropriate areas. The SDT removed the requirements in Requirements R1 and R2 for the coordination of plans with "impacted" entities. The SDT corrected the term Capacity and changed it to reflect the defined term "Capacity Emergency." In Requirement R4, the "as soon as practical" was removed. While the new IRO standards speak to the notifications, the SDT maintained the requirement since the standard is not an approved standard at this time.
American Electric Power	The drafting team's consideration of comments document states the following: "The EOP SDT discussed the many suggestions received for Requirement R1 and its detailed requirement parts. Based on comments received, the EOP SDT added details into the Requirement R1 Rationale that if any Requirement R1 Parts are not applicable, that the Transmission Operator should note "not applicable" in their plan." We find no mention of this in the R1 callout, though similar language is included in the callout for R2. Regardless, while we agree with such an allowance, we believe it should be included in the standard itself. Otherwise, an auditor could strictly adhere to the standard where it states "shall include the following elements." EOP SDT Response: The SDT appreciates your comments and has made this change.
FRCC	There is a potential for confusion due the SDTs use of the terms "Emergency Operation Plan". It appears that the SDTs intent is for readers to utilize the definitions in the Glossary of Terms for "Emergency" and "Operating Plan" to determine what is required by the Standard. The combining of these two definitions is confusing. If the SDT decides that the continued use of "Emergency Operation Plan" is needed, then a new definition should be developed to provide clarity around the intent and content of the plan. Therefore, the potential confusion of what an "Emergency

Organization	Question 7 Comment
	Operating Plan" actually entails could create difficulties when assessing compliance and is directly related to the 'measures' and the 'enforceability' of the requirements. The use of the term 'implement' in requirements R1 and R2 is confusing when compared to the language in Measures M1 and M2 and the RSAW. What does 'implement' actually mean in the context of the requirements? The requirements (R1 and R2) require an Emergency Operating Plan to be developed, maintained and implemented. Does this mean that the plan will be developed to include the required attributes identified in the requirement sub-bullets, will be maintained with periodic reviews to ensure the plan will appropriately address the specific emergency condition and be implemented. I believe implemented means that the plan is available for the System Operator's use, training has been completed and the Operators are proficient in the application of the plan. But when you read the Measure and the RSAW they are looking for evidence that the plan was actually activated in response to an emergency which is not part of R1 and R2. So if the plan is never used by the operator is that part of the audit over?R3 requires approval of the plan from the RC, but there is not documented criteria for the RC to assess approval and therefore is very difficult to assess compliance. Unless this is simply an exercise in documenting a 'yes' or 'no' EOP SDT Response: The SDT appreciates your comments and has separated the two defined terms. The term "implemented" is meant in the context of all the above statements made by the commentator. The SDT's intent is that either entity that has an Operating Plan to mitigate Emergencies will have it so that operators will be trained on it and use it if needed.
Southern Indiana Gas and Electric Company d/b/a Vectren Energy Delivery of Indiana	Vectren appreciates the work of the standards drafting team, and generally supports the standard.
NV Energy	We commend the drafting team on their work to consolidated these multiple standards, streamlining the compliance requirements. Our negative vote on this draft stems from the concerns around the required coordination of manual and automatic load shedding as well as the consequences created with the language changes in the EEA Level 2 and 3 criteria.

Organization	Question 7 Comment
	EOP SDT Response: The SDT appreciates your comments and has made numerous modifications to the draft based on the comments received from the industry on the items the commenter has mentioned.

Additional Comments:

Austin Energy
Thomas Standifur

1. Based on comments from stakeholders, the EOP SDT has added the term “Operator-Controlled” preceding the language “manual Load shedding” in Parts of Requirements R1 and R2. Do you agree with this revision? If not, please provide specific suggestions for change in the comment area.

   ☒ Yes
   ☐ No
   Comments:

2. Based on comments from a majority of stakeholders, the EOP SDT removed Requirement 3 from EOP-011-1 draft 1 and has placed the requirement on the Balancing Authority and Transmission Operator to coordinate their Emergency Operating Plans with impacted Balancing Authorities and Transmission Operators. Do you agree with this revision? If not, please provide specific suggestions for change in the comment area.

   ☒ Yes
   ☐ No
   Comments:

3. The EOP SDT received several comments regarding Reliability Coordinator approval of Balancing Authority and Transmission Operator Emergency Operating Plans. The FERC directive in Paragraph 548 or Order 693 mandates that the Reliability Coordinator be included as an applicable entity; while plan approval by the Reliability Coordinator was

not a specific mandated intent, the EOP SDT believes that approval by the Reliability Coordinator reduces risk to reliability of the BES. Do you agree with this approach? If not, please provide specific suggestions for change in the comment area.

☐ Yes
☒ No

Comments: City of Austin dba Austin Energy (AE) does not believe Reliability Coordinators need to approve individual entity's Emergency Operating Plans. The effort presents an administrative burden on both the RC and the BA/TOP RC. AE believes the benefit of RC involvement could be in the concept of the RC coordination from the wide-area perspective. AE further believes RC coordination should not require RC approval. The RC could receive plans and be required to comment only if it identifies coordination issues. However, the SDT removed that concept (formerly R3) in this draft, and AE supports that decision. With the removal of the coordination role for the RC, AE remains unclear as to the intent of the RC approval. AE respectfully asks the SDT to remove this concept from the proposed versions of EOP-011-1 in consideration of Paragraph 81 criteria regarding administrative burden with no benefit to reliability. Further AE suggests considering the inclusion of the Reliability Coordinator in R4 and R5 as a response to the FERC directive in Paragraph 548 of Order 693.

EOP SDT Response: The SDT appreciates your comments and have removed the requirement that the RC approve an Operating Plan to mitigate Emergencies.

4. The EOP SDT has removed Requirement R5 from EOP-011-1 draft 1, as it is redundant with currently-enforceable TOP-001-1a. Do you agree with this revision? If not, please explain in the comment area below.

☒ Yes
☐ No

Comments: City of Austin dba Austin Energy (AE) supports the removal of R5 from EOP-011-1 draft 1 due to redundancy with TOP-001-1a. It seems, however, the SDT moved the concept into R1 Part 1.2.1 and R2 Part 2.2 of EOP-011-1 draft 2. AE disagrees with the addition of these parts to R1 and R2 for the same reasons (redundancy) as before.

EOP SDT Response: The SDT appreciates your comments. The SDT kept Requirement Part R1.2.1 and Requirement Part R2.2 because they are describing that the TOP and BA need a process in place so that a notification can be made to the RC. These requirements are not saying that a notification take place, but that a process needs to be included in the Operating Plan to mitigate Emergencies.

5. The EOP SDT has revised Attachment 1, removing “Operating Reserves” from EEA 2 and adding “Operating Reserves” into EEA 3. Do you agree with this change? If not, please explain in the comment area below.

☐ Yes
☐ No
Comments: [intentionally left blank]

6. Do you agree with the VRFs and VSLs in EOP-011-1? If not, please indicate which Requirement(s) and specifically what you disagree with, and provide suggestions for improvement.

☒ Yes
☐ No
Comments:

7. If you have any other comments on this Standard that you haven’t already mentioned above, please provide them here:

Comments: (1) City of Austin dba Austin Energy (AE) seeks clarity stating the Emergency Operating Plan required under R1 can be a single document or a combination of documents. This is similar to the allowance for a plan or set of plans in currently enforceable EOP-001-2.1b. (2) AE suggests the SDT remove the phrase “and generation” from R1, Part 1.2.3, as the TOP does not have control over generation outages. (3) AE suggests the SDT remove R1, Part 1.2.5, “Redispatch of generation request.” The TOP does not have the responsibility of generation dispatch nor does it necessarily have the visibility into the system to appropriately request generation redispatch.

EOP SDT Response: The SDT appreciates your comments. The SDT has modified these requirements based on industry comments, but has retained the intent that an entity must have a process in place to have these actions carried out, especially if they are not responsible for carrying out these actions.

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Standards Committee authorized moving the SAR forward to standard development 10/17/2013.
2. SAR posted for comment 11/06/13-12/05/13.
3. Informal posting for comment 03/28/14-04/28/14.
4. Initial formal posting for comment with parallel initial ballot 07/02/14-08/15/14.

Description of Current Draft

This is the third draft of the proposed standard and is being posted for formal stakeholder comments and initial ballot. This draft includes the modifications based on the Five-Year Review Team recommendations, comments submitted by stakeholders during the SAR comment period, the informal comment period, the formal comment period, other items identified in the SAR, and applicable FERC directives from FERC Order No. 693.

Anticipated Actions	Anticipated Date
Additional 45-day Formal Comment Period with Parallel Initial Ballot	September 2014
Final ballot	October 2014
BOT adoption	November 2014

Effective Dates

The standard shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Initial Standard	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

Definitions of Terms Used in Standard

This section includes all newly-defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The Emergency Operations Standard Drafting Team (EOP SDT) proposes to revise the current approved definition of **Energy Emergency** as follows:

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its ~~customers'~~ expected ~~energy~~ Load obligations.

The proposed revisions are intended to clarify that an Energy Emergency is not necessarily limited to a Load-Serving Entity. This term, or variations of it, are also used in other standards, as indicated below. The EOP SDT is obligated to review other standards in which this term is used to determine if reliability gaps or redundancies are created by the proposed revision to the defined term. The EOP SDT does not believe that the proposed revisions change the reliability intent of other requirements or definitions. The following is a list of standards and definitions using the term:

- **BAL-002-WECC – Contingency Reserve**: This standard becomes enforceable on October 1, 2014. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **IRO-005-3.1a — Reliability Coordination — Current Day Operations** - This standard was revised under Project 2006-06 and the reference to Energy Emergency was removed from the standard. The standard was approved by the NERC BOT and filed with FERC. NERC has requested that FERC defer action on its petition and is revising this standard under Project 2014-03, TOP/IRO Reliability Standards. This project is scheduled to be completed no later than January 31, 2015. The two standard drafting teams are coordinating the definition revision to ensure there are no redundancies.
- **MOD-004-1 — Capacity Benefit Margin:** This standard is being retired and replaced with MOD-001-2 — Modeling, Data, and Analysis — Available Transmission System Capability (NERC BOT approved February 6, 2014). The term "Energy Emergency" is not used in the new standard. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability to the existing approved standard.
- **INT-004-3 – Dynamic Transfers:** This standard was a revision to INT-004-2 under Project 2008-12. INT-004-3 was approved by the NERC BOT and filed with FERC. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **Defined term Emergency Request for Interchange:** This term is not used in any existing approved standard.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Emergency Operations**
2. **Number: EOP-011-1**
3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plan(s) to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator Area.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator
5. **Background:**

   EOP-011-1 consolidates requirements from three standards: EOP-001-2.1b, EOP-002-3.1, and EOP-003-2.

   The standard streamlines the requirements for Emergency operations for the Bulk Electric System (BES) into a clear and concise standard that is organized by Functional Entity. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan;

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to the Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

1.2.6. Reliability impacts of extreme weather conditions.

Rationale for Requirement R1:

The EOP SDT examined the recommendation of the EOP FYRT and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Transmission Operator to create an Operating Plan for mitigating operating Emergencies in its Transmission Operator Area.

The Operating Plan can be one plan, or it can be multiple plans.

"Notification to the Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency" was retained. This is a process in the plan that determines how you will make a notification to the Reliability Coordinator.

To meet the associated measure, an entity would likely provide evidence that such an evaluation was conducted along with an explanation of why any overlap of Loads between manual and automatic load shedding was unavoidable or reasonable.

If any Parts of Requirement R1 are not applicable, the Transmission Operator should note "not applicable" in the Operating plan.

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shed schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R1 Part 1.2.6 is to minimize, as much as possible, the use of manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If any entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review their automatic Load shedding schemes and coordinate their manual processes so that any overlapping use of Loads is avoided to the extent reasonably possible.

M1. Each Transmission Operator will have a dated Operating Plan developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan;

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

2.2.9. Reliability impacts of extreme weather conditions.

Rationale for Requirement R2: To address the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1, the EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. EOP-011-1 also establishes a separate requirement for the Balancing Authority to create its Emergency Operating Plan to address Capacity and Energy Emergencies.

The Operating Plan can be one plan, or it can be multiple plans.

An Operating Plan is implemented by carrying out its stated actions.

If any Parts of Requirement R2 are not applicable, the Balancing Authority should note “not applicable” in the Operating Plan.

The EOP SDT retained the statement “Operator-controlled manual Load shedding,” as it was in the current EOP-003-2 and is consistent with the intent of the EOP SDT.

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT’s intent is to keep manual and automatic Load shedding schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R2 Part 2.2.8. is to minimize as much as possible the use manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If an entity manually sheds a Load that was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review its automatic Load shedding schemes and coordinate its manual processes so that any overlapping use of Loads is avoided to the extent possible.

The EOP SDT retained Requirement R8 from EOP-002-3.1 and added it to the Parts in Requirement R2.

M2. Each Balancing Authority will have a dated Operating Plan developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator, within 30 calendar days of receipt, shall review each Operating Plan to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans.

3.1. The Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan on the basis of compatibility and inter-dependency with other Balancing Authorities’ and Transmission Operators’ Operating Plans;

3.1.2. Review each submitted Operating Plan for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

Rationale for R3: The SDT agreed with industry comments that the Reliability Coordinator does not need to approve BA and TOP plans. The SDT has changed this requirement to remove the approval but still require the RC to review each entity's plan, looking specifically for reliability risks. This is consistent with the Reliability Coordinator's role within the Functional Model and meets the FERC directive regarding the RC's involvement in Operating Plans for mitigating emergencies.

M3. The Reliability Coordinator will have documentation, such as dated e-mails or other correspondences that it reviewed Transmission Operator and Balancing Authority Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

Rationale for Requirement R4: Requirement R4 supports the coordination of Operating Plans within a Reliability Coordinator Area in order to identify and correct any Wide Area reliability risks. The EOP SDT expects the Reliability Coordinator to make a reasonable request for response time. The time period requested by the Reliability Coordinator to the Transmission Operator and Balancing Authority to update the Operating Plan will depend on the scope and urgency of the requested change.

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan version history showing that it responded and updated the Operating Plan within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R5: The EOP SDT used the existing requirement in EOP-002-3.1 for the Balancing Authority and added the words "within 30 minutes from the time of receiving notification" to the requirement to communicate the intent that timeliness is important, while balancing the concern that in an Emergency there may be a need to alleviate excessive notifications on Balancing Authorities and Transmission Operators. By adding this time limitation, a measurable standard is set for when the Reliability Coordinator must complete these notifications.

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators .

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R6: Requirement R6 was created to address the FERC directive to have the Reliability Coordinator involved to ensure that the Energy Emergency Alert is declared.

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The Balancing Authority, Reliability Coordinator, and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Transmission Operator shall retain the current Operating Plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4and Measures M1 and M4.
- The Balancing Authority shall retain the current Operating Plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

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

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-Report

Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Real-time Operations, Operations Planning, Long-term Planning**	**High**		The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies on its Transmission Operator Area but failed to maintain it.	The Transmission Operator developed an Operating Plan to mitigate operating Emergencies in its Transmission Operator Area but failed to have it reviewed by the Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies in its Transmission s Operator Area but failed to implement it.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	**Real-time Operations, Operations Planning, Long-term Planning**	**High**	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies but failed to maintain it.	The Balancing Authority developed an Operating Plan to mitigate operating Emergencies but failed to have it reviewed by the Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan to mitigate operating Emergencies. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies but failed to implement it.
R3	**Operations Planning**	**High**	N/A	N/A	The Reliability Coordinator identified a reliability risk but	The Reliability Coordinator identified a reliability

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					failed to notify the Balancing Authority or Transmission Operator within 30 days.	risk but failed to notify the Balancing Authority or Transmission Operator.
R4	**Operations Planning**	**High**	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit the Operating Plan to the Reliability Coordinator within the timeframe specified by the Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit the Operating Plan to the Reliability Coordinator.
R5	**Real-time Operations**	**High**	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify impacted Reliability Coordinators,	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify impacted Reliability

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Balancing Authorities and Transmission Operators but did not notify within 30 minutes from the time of receiving notification.	Coordinators, Balancing Authorities and Transmission Operators.
R6	**Real-time Operations**	**High**	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Attachment 1-EOP-011-1
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

LSEs were removed from Attachment 1, as an LSE has no Real-time reliability functionality with respect to EEAs.

EOP-002-3.1 Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ E-tag Specification v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all adjacent Reliability Coordinators.

Rationale for (2) Notification: The EOP SDT deleted the language, "*The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between RCs shall be held as necessary to communicate system conditions. The RC shall also notify the other RCs when the alert has ended*" as duplicative to proposed IRO-014-3 Requirement R1:

R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:

1.1 Communications and notifications, and the process to follow in making those notifications.

1.2 Energy and capacity shortages.

1.3 Control of voltage, including the coordination of reactive resources.
Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

1.5 Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas.

1.6 Provisions for weekly conference calls.

B. EEA Levels

Introduction
To ensure that all Reliability Coordinator s clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinator s will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards. The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use.**

Circumstances:

- The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. **EEA 2 — Load management procedures in effect**.

Circumstances:

- The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
- An energy deficient Balancing Authority has implemented its Operating Plan to mitigate Emergencies.
- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinator s and energy deficient Balancing Authorities s have the following responsibilities:

2.1 Notifying other Balancing Authorities **and market participants**. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the impacted Reliability Coordinator s, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. The Reliability Coordinator of a Balancing Authority with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator to see if it's possible to return any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

Rationale for EEA 2: The EOP SDT modified the "Circumstances" for EEA 2 to show that an entity will be in this level when it has implemented its Operating Plan to mitigate Emergencies but is still able to maintain Contingency reserves.

3. EEA 3 —Firm Load interruption is imminent or in progress.

Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinator s and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the impacted Reliability Coordinator s, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinator s and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre-Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the impacted Reliability Coordinator s (via the RCIS), Balancing Authorities and Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA**.**

0.1 Notification. The Reliability Coordinator shall notify all other Reliability Coordinator s via the RCIS of the termination. The Reliability Coordinator shall also notify the impacted Balancing Authorities and Transmission Operators.

Guidelines and Technical Basis

Rationales to be added here after balloting.

Requirement R1:

Requirement R2:

Requirement R3:

Requirement R4:

Requirement R5:

Requirement R6:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. Standards Committee authorized moving the SAR forward to standard development 10/17/2013.
2. SAR posted for comment 11/06/13-12/05/13.
3. Informal posting for comment 03/28/14-04/28/14.
4. Initial formal posting for comment with parallel initial ballot 07/02/14-08/15/14.

Description of Current Draft

This is the ~~second~~third draft of the proposed standard and is being posted for formal stakeholder comments and initial ballot. This draft includes the modifications based on the Five-Year Review Team recommendations, comments submitted by stakeholders during the SAR comment period, ~~comments submitted by stakeholders during~~ the informal comment period, ~~as well as~~the formal comment period, other items identified in the SAR, and applicable FERC directives from FERC Order No. 693.

Anticipated Actions	Anticipated Date
Additional 45-day Formal Comment Period with Parallel Initial Ballot	~~July~~September 2014
Final ballot	October 2014
BOT adoption	November 2014
~~File standard with regulatory authorities~~	~~December 2014~~

Effective Dates

The standard shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Version History

Version	Date	Action	Change Tracking
1	TBD	Initial Standard	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

Definitions of Terms Used in Standard

This section includes all newly-defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The Emergency Operations Standard Drafting Team (EOP SDT ~~proposed~~) proposes to revise the current approved definition of **Energy Emergency** as follows:

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its ~~customers'~~ expected ~~energy~~ Load obligations.

The proposed revisions are intended to clarify that an Energy Emergency is not necessarily limited to a Load-Serving Entity. This term, or variations of it, are also used in other standards, as indicated below. The EOP SDT is obligated to review other standards in which this term is used to determine if reliability gaps or redundancies are created by the proposed revision to the defined term. The EOP SDT does not believe that the proposed revisions change the reliability intent of other requirements or definitions. The following is a list of standards and definitions using the term:

- **BAL-002-WECC – Contingency Reserve**: This standard becomes enforceable on October 1, 2014. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **IRO-005-3.1a — Reliability Coordination — Current Day Operations** - This standard was revised under Project 2006-06 and the reference to Energy Emergency was removed from the standard. The standard was approved by the NERC BOT and filed with FERC. NERC has requested that FERC defer action on its petition and is revising this standard under Project 2014-03, TOP/IRO Reliability Standards. This project is scheduled to be completed no later than January 31, 2015. The two standard drafting teams are coordinating the definition revision to ensure there are no redundancies.
- **MOD-004-1 — Capacity Benefit Margin:** This standard is being retired and replaced with MOD-001-2 — Modeling, Data, and Analysis — Available Transmission System Capability (NERC BOT approved February 6, 2014). The term "Energy Emergency" is not used in the new standard. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability to the existing approved standard.
- **INT-004-3 – Dynamic Transfers:** This standard was a revision to INT-004-2 under Project 2008-12. INT-004-3 was approved by the NERC BOT and filed with FERC. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **Defined term Emergency Request for Interchange:** This term is not used in any existing approved standard.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-1**

3. **Purpose:** To ~~mitigate~~address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed ~~Emergency~~ Operating ~~Plans~~Plan(s) to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator Area.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

5. **Background:**

EOP-011-1 consolidates requirements from three standards: EOP-001-2.1b, EOP-002-3.1, and EOP-003-2.

~~The Project 2009-03 Emergency Operations Standard Drafting Team (EOP SDT) developed EOP-011-1 by considering the following inputs:~~

- ~~Applicable FERC directives;~~
- ~~Five Year Review Team (FYRT) recommendations;~~
- ~~Independent Expert Review Panel recommendations; and~~
- ~~Paragraph 81 criteria.~~

The standard streamlines the requirements for Emergency operations for the Bulk Electric System (BES) into a clear and concise standard that is organized by Functional Entity. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-~~approved~~reviewed ~~Emergency~~ Operating Plan to mitigate operating Emergencies ~~on~~in its Transmission ~~System. At a minimum, the Emergency~~Operator Area. The Operating Plan shall include the following ~~elements~~, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities ~~to activate~~for activating the ~~Emergency~~ Operating Plan;

1.2. ~~Strategies~~Processes to prepare for and mitigate Emergencies including~~, at a minimum:~~:

1.2.1. Notification to the Reliability Coordinator, to include current and projected ~~System~~ conditions, when experiencing an operating Emergency;

~~**1.2.2.** Voltage control;~~

~~**1.2.3.**~~**1.2.2.** Cancellation or recall of Transmission and generation outages;

~~**1.2.4.**~~**1.2.3.** ~~System~~Transmission system reconfiguration;

~~**1.2.5.**~~**1.2.4.** Redispatch of generation request;

~~**1.2.6.**~~**1.2.5.** ~~Operator~~Provisions for operator-controlled manual Load shedding ~~plan coordinated to minimize~~that minimizes the ~~use of~~overlap with automatic Load shedding~~;~~ and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

~~**1.2.7.**~~**1.2.6.** ~~Mitigation of reliability~~ Reliability impacts of extreme weather conditions~~; and~~.

~~**1.3.** Strategies for coordinating Emergency Operating Plans with impacted Transmission Operators and impacted Balancing Authorities.~~

Rationale for Requirement R1:

The EOP SDT examined the recommendation of the EOP FYRT and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Transmission Operator to create an Operating Plan for mitigating operating Emergencies in its Transmission Operator Area.

The Operating Plan can be one plan, or it can be multiple plans.

"Notification to the Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency" was retained. This is a process in the plan that determines how you will make a notification to the Reliability Coordinator.

To meet the associated measure, an entity would likely provide evidence that such an evaluation was conducted along with an explanation of why any overlap of Loads between manual and automatic load shedding was unavoidable or reasonable.

If any Parts of Requirement R1 are not applicable, the Transmission Operator should note "not applicable" in the Operating plan.

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shed schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R1 Part 1.2.6 is to minimize, as much as possible, the use of manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If any entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review their automatic Load shedding schemes and coordinate their manual processes so that any overlapping use of Loads is avoided to the extent reasonably possible.

M1. Each Transmission Operator will have a dated ~~and approved Emergency~~ Operating Plan developed in accordance with Requirement R1 ~~that has been approved~~and reviewed by its Reliability Coordinator~~,~~; evidence such as ~~shown with the documented approval from its Reliability Coordinator~~a review or revision history to indicate that the Operating Plan has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its ~~plan~~Operating Plan was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-~~approved Emergency~~reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. ~~At a minimum, the Emergency~~The Operating

Plan shall include the following ~~elements~~, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities ~~to activate~~for activating the ~~Emergency~~ Operating Plan;

2.2. Processes to prepare for and mitigate Emergencies including:

~~2.1.1.~~2.2.1. Notification to the Reliability Coordinator, to include current and projected ~~System~~ conditions~~,~~ when experiencing a Capacity Emergency or Energy Emergency;

~~2.1.2.~~2.2.2. ~~Criteria to declare~~Requesting an Energy Emergency Alert, per Attachment 1;

~~**2.2.** Strategies to prepare for and mitigate Emergencies including, at a minimum:~~

~~2.2.1.~~2.2.3. ~~Generating~~Managing generating resources in its Balancing Authority Area to address:

~~2.2.1.1.~~2.2.3.1. capability and availability;

~~2.2.1.2.~~2.2.3.2. fuel supply and inventory concerns;

~~2.2.1.3.~~2.2.3.3. fuel switching capabilities; and

~~2.2.1.4.~~2.2.3.4. environmental constraints.

~~2.2.2.~~2.2.4. ~~Voluntary~~Public appeals for voluntary Load reductions;

~~**2.2.3.** Public appeals;~~

~~2.2.4.~~2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

~~2.2.5.~~2.2.6. Reduction of internal utility energy use;

~~**2.2.6.** Customer fuel switching;~~

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. ~~Operator~~Provisions for operator-controlled manual Load shedding ~~plan coordinated to minimize~~that minimizes the ~~use of~~overlap with automatic Load shedding~~;~~ and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

2.2.9. ~~Mitigation of reliability~~ Reliability impacts of extreme weather conditions.

~~**2.3.** Strategies for coordinating Emergency Operating Plans with impacted Balancing Authorities and impacted Transmission Operators.~~

Rationale for Requirement R2: To address the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1, the EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. EOP-011-1 also establishes a separate requirement for the Balancing Authority to create its Emergency Operating Plan to address Capacity and Energy Emergencies.

The Operating Plan can be one plan, or it can be multiple plans.

An Operating Plan is implemented by carrying out its stated actions.

If any Parts of Requirement R2 are not applicable, the Balancing Authority should note "not applicable" in the Operating Plan.

The EOP SDT retained the statement "Operator-controlled manual Load shedding," as it was in the current EOP-003-2 and is consistent with the intent of the EOP SDT.

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shedding schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R2 Part 2.2.8. is to minimize as much as possible the use manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If an entity manually sheds a Load that was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review its automatic Load shedding schemes and coordinate its manual processes so that any overlapping use of Loads is avoided to the extent possible.

The EOP SDT retained Requirement R8 from EOP-002-3.1 and added it to the Parts in Requirement R2.

M2. Each Balancing Authority will have a dated ~~and approved Emergency~~ Operating Plan developed in accordance with Requirement R2 ~~that has been approved~~and reviewed by its Reliability Coordinator~~,~~; evidence such as ~~shown with the documented approval from its Reliability Coordinator~~a review or revision history to indicate that the Operating Plan has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its ~~plan~~Operating Plan was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. ~~Each~~The Reliability Coordinator ~~shall approve or disapprove, with stated reasons for disapproval, Emergency Operating Plans submitted by Transmission Operators and Balancing Authorities,~~ within 30 calendar days of ~~submittal.~~receipt, shall review each Operating Plan to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans.

3.1. The Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan for coordination to avoid risk to Wide Area reliability; and

~~**2.3.1.**~~**3.1.3.** Notify each Balancing Authority and Transmission Operator of the results. *[Violation Risk Factor: ~~Medium~~High] [Time Horizon: Operations Planning]*

Rationale for R3: The SDT agreed with industry comments that the Reliability Coordinator does not need to approve BA and TOP plans. The SDT has changed this requirement to remove the approval but still require the RC to review each entity's plan, looking specifically for reliability risks. This is consistent with the Reliability Coordinator's role within the Functional Model and meets the FERC directive regarding the RC's involvement in Operating Plans for mitigating emergencies.

M3. The Reliability Coordinator will have documentation, such as dated e-mails ~~with receipts~~ or ~~registered mail receipts,~~other correspondences that it ~~approved or disapproved, with stated reasons for disapproval, the~~reviewed Transmission Operator and Balancing Authority ~~submitted and revised Emergency~~ Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

Rationale for Requirement R4: Requirement R4 supports the coordination of Operating Plans within a Reliability Coordinator Area in order to identify and correct any Wide Area reliability risks. The EOP SDT expects the Reliability Coordinator to make a reasonable request for response time. The time period requested by the Reliability Coordinator to the Transmission Operator and Balancing Authority to update the Operating Plan will depend on the scope and urgency of the requested change.

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan version history showing that it responded and updated the Operating Plan within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

~~R3.~~R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, ~~as soon as practical~~within 30 minutes from the time of receiving notification, other ~~impacted Reliability Coordinators,~~ Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R5: The EOP SDT used the existing requirement in EOP-002-3.1 for the Balancing Authority and added the words "within 30 minutes from the time of receiving notification" to the requirement to communicate the intent that timeliness is important, while balancing the concern that in an Emergency there may be a need to alleviate excessive notifications on Balancing Authorities and Transmission Operators. By adding this time limitation, a measurable standard is set for when the Reliability Coordinator must complete these notifications.

~~M4.~~M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if ~~it~~the Reliability Coordinator communicated ~~the Balancing Authority's or Transmission Operator's Emergency to impacted Reliability Coordinators,~~, in accordance with Requirement R5, with other Balancing Authorities~~,~~ and Transmission Operators in ~~accordance with Requirement R4~~its Reliability Coordinator Area, and neighboring Reliability Coordinators .

~~R4.~~R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall ~~initiate~~declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R6: Requirement R6 was created to address the FERC directive to have the Reliability Coordinator involved to ensure that the Energy Emergency Alert is declared.

~~M5.~~M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it ~~initiated~~declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement ~~R5~~R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The Balancing Authority, Reliability Coordinator, and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Transmission Operator shall retain the current ~~Emergency~~ Operating Plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for ~~Requirement~~Requirements R1~~,~~ and ~~Measure~~R4and Measures M1 and M4.
- The Balancing Authority shall retain the current ~~Emergency~~ Operating Plan, evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for ~~Requirement~~Requirements R2~~,~~ and ~~Measure~~R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, ~~R4~~R5, and ~~R5~~R6 and Measures M3, ~~M4~~M5, and ~~M5~~M6.

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

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

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Check

Compliance Investigation

Self-~~Reporting~~Report

~~Complaints~~Complaint

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Real-time Operations, Operations Planning, Long-term Planning**	**High**	~~The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to include one of the Sub-Parts 1.2.1 – 1.2.7 as applicable.~~	The Transmission Operator ~~had~~developed a Reliability Coordinator-~~approved~~ ~~Emergency~~reviewed Operating Plan to mitigate operating Emergencies on its Transmission ~~System~~Operator Area but failed to ~~include two of the Sub-Parts 1.2.1 – 1.2.7 as applicable~~maintain it.	The Transmission Operator ~~had a Reliability Coordinator-approved~~ ~~Emergency~~developed an Operating Plan to mitigate operating Emergencies ~~on~~in its Transmission ~~System~~Operator Area but failed to ~~include three of the Sub-Parts 1.2.1 – 1.2.7 as applicable.~~ ~~OR~~ ~~The Transmission Operator failed to~~ have ~~a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its~~	The Transmission Operator ~~had a Reliability Coordinator-approved~~ ~~Emergency~~failed to develop an Operating Plan to mitigate operating Emergencies ~~on~~in its Transmission ~~System but failed to include four or more of the Sub-Parts 1.2.1 – 1.2.7.~~ ~~OR~~ ~~The Transmission~~ Operator Area . OR ~~failed to have~~The Transmission Operator developed

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					~~Transmission System but failed to include either Part 1.1 or Part 1.3.~~ ~~OR~~ ~~The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System but failed to maintain~~ it~~.~~ reviewed by the Reliability Coordinator.	a Reliability Coordinator-~~approved Emergency~~reviewed Operating Plan to mitigate operating Emergencies ~~on~~in its Transmission ~~System.~~ ~~OR~~ ~~The Transmission Operator had a Reliability Coordinator-approved Emergency Operating Plan to mitigate operating Emergencies on its Transmission System~~s Operator Area but failed to implement it ~~for an operating~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						~~Emergency~~.
R2	**Real-time Operations, Operations Planning, Long-term Planning**	**High**	~~The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to include one of the Sub-Parts 2.4.1 – 2.4.9.~~ N/A	The Balancing Authority ~~had~~developed a Reliability Coordinator-~~approved Emergency~~reviewed Operating Plan to mitigate ~~Capacity and Energy~~operating Emergencies but failed to ~~include two of the Sub-Parts 2.4.1 – 2.4.9.~~maintain it.	The Balancing Authority ~~had a Reliability Coordinator-approved Emergency~~developed an Operating Plan to mitigate ~~Capacity and Energy~~operating Emergencies but failed to ~~include three of~~have it reviewed by the ~~Sub-Parts 2.4.1 – 2.4.9.~~Reliability Coordinator. ~~OR~~ ~~The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but~~	The Balancing Authority ~~had a Reliability Coordinator-approved Emergency~~failed to develop an Operating Plan to mitigate ~~Capacity and Energy~~operating Emergencies ~~but failed to include four or more of the Sub-Parts 2.4.1 – 2.4.9.~~. OR The Balancing Authority ~~failed to have~~developed a Reliability Coordinator-

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					~~failed to include either Part 2.1 or Part 2.2 or Part 2.3 or Part 2.5.~~ ~~OR~~ ~~The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy Emergencies but failed to maintain it.~~	~~approved Emergency~~reviewed Operating Plan to mitigate ~~Capacity and Energy Emergencies.~~ ~~OR~~ ~~The Balancing Authority had a Reliability Coordinator-approved Emergency Operating Plan to mitigate Capacity and Energy~~operating Emergencies but failed to implement it ~~for a Capacity or Energy Emergency~~.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	Operations Planning	High	N/A	N/A	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator within 30 days.	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator.
~~R3~~R4	Operations Planning	~~Medium~~High	~~The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 30 days but less~~	~~The Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans in more than 40 days but less than or equal to 50 days.~~N/A	The ~~Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a~~ Transmission Operator ~~and~~or Balancing Authority ~~submitted or revised Emergency Operating Plans in more than 50 days but less than or equal to 60 days.~~ ~~OR~~ ~~The~~failed to update and resubmit the	The ~~Reliability Coordinator approved or disapproved, with stated reasons for disapproval, a~~ Transmission Operator ~~and~~or Balancing Authority ~~submitted or revised Emergency~~failed to update and resubmit the Operating ~~Plans in~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
			~~than or equal to 40 days.~~N/A		Operating Plan to the Reliability Coordinator within the timeframe specified by the Reliability Coordinator ~~disapproved a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans within 30 calendar days of submittal but failed to provide the reasons for disapproval~~.	~~more than 60 days.~~ ~~OR~~ ~~The Reliability Coordinator failed to approve or disapprove, with stated reasons for disapproval, a Transmission Operator and Balancing Authority submitted or revised Emergency Operating Plans~~Plan to the Reliability Coordinator.
~~R4~~R5	**Real-time Operations**	**High**	N/A	N/A	The Reliability Coordinator that received an Emergency notification from a Transmission Operator	The Reliability Coordinator that received an Emergency notification from a Transmission

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					or Balancing Authority did notify ~~other~~ impacted Reliability Coordinators, Balancing Authorities and Transmission Operators but did not ~~do so as soon as practical.~~notify within 30 minutes from the time of receiving notification.	Operator or Balancing Authority failed to notify~~, as soon as practical,~~ ~~other~~ impacted Reliability Coordinators, Balancing Authorities and Transmission Operators.
~~R5~~R6	**Real-time Operations**	**High**	N/A	~~The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to notify the other Reliability Coordinators, Balancing Authorities and Transmission Operators when the alert has ended.~~N/A	~~The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency Alert and hold conference calls between Reliability Coordinators as necessary to~~	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to ~~initiate~~declare an Energy Emergency Alert ~~and notify all other Reliability~~

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					~~communicate System conditions.~~N/A	~~Coordinators of the situation via the Reliability Coordinator Information System (RCIS). ~~. ~~OR~~ ~~The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to initiate an Energy Emergency Alert and notify all Balancing Authorities and Transmission Operators in its reliability area.~~

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Attachment 1-EOP-011-1
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator ~~(RC)~~ in which it communicates the condition of a Balancing Authority ~~(BA)~~ which is experiencing an Energy Emergency.

LSEs were removed from Attachment 1, as an LSE has no Real-time reliability functionality with respect to EEAs.

EOP-002-3.1 Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.

A. General Responsibilities

1. **Initiation by ~~RC.~~Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a ~~RC~~ Reliability Coordinator at 1) the ~~RC's~~Reliability Coordinator's own request, or 2) upon the request of ~~the requesting BA~~an energy deficient Balancing Authority.
2. **Notification**. A ~~RC~~Reliability Coordinator who declares an EEA shall notify all ~~BAs~~Balancing Authorities and Transmission Operators ~~(TOP)~~ in its Reliability Coordinator Area. The ~~RC~~Reliability Coordinator shall also notify all ~~other RCs of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between RCs shall be held as necessary to communicate System conditions. The RC shall also notify the other RCs, Bas, and TOPs when the EEA has ended~~adjacent Reliability Coordinators.

Rationale for (2) Notification: The EOP SDT deleted the language, "The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between RCs shall be held as necessary to communicate system conditions. The RC shall also notify the other RCs when the alert has ended" as duplicative to proposed IRO-014-3 Requirement R1:
"R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:

- **1.1** Communications and notifications, and the process to follow in making those notifications.
- **1.2** Energy and capacity shortages.
- **1.3** Control of voltage, including the coordination of reactive resources.

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

- **1.5** Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas.
- **1.6** Provisions for weekly conference calls."

B. EEA Levels

Introduction

To ensure that all ~~RCs~~Reliability Coordinator s clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established ~~four~~three levels of EEAs. The ~~RCs~~Reliability Coordinator s will use these terms when ~~explaining~~communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC ~~reliability standard. The RC~~Reliability Standards. The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. **EEA 1 — All available generation resources in use.**

Circumstances:

- ~~Requesting BA~~The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required ~~Operating~~Contingency Reserves.

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. EEA 2 — Load management procedures in effect.

Circumstances:

- ~~Requesting BA~~The Balancing Authority is no longer able to provide its ~~customers'~~ expected energy requirements and is an energy deficient Balancing Authority.
- ~~Requesting BA~~An energy deficient Balancing Authority has implemented its ~~approved Emergency Operations~~Operating Plan to mitigate Emergencies.
- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, ~~RCs and requesting BAs~~Reliability Coordinator s and energy deficient Balancing Authorities s have the following responsibilities:

2.1 Notifying other ~~BAs~~Balancing Authorities **and market participants**. ~~The requesting BA~~The energy deficient Balancing Authority shall communicate its needs to other ~~BAs~~Balancing Authorities and market participants. Upon request from the ~~requesting BA~~energy deficient Balancing Authority, the respective ~~RC~~Reliability Coordinator shall post the declaration of the alert level, along with the name of the ~~requesting BA~~energy deficient Balancing Authority on the RCIS website.

2.2 **Declaration period.** ~~The requesting BA~~The energy deficient Balancing Authority shall update its ~~RC~~Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the impacted Reliability Coordinator s, Balancing Authorities and Transmission Operators**.**

2.3 **Sharing information on resource availability.** The Reliability Coordinator of a Balancing Authority with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 **Evaluating and mitigating Transmission limitations.** The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator to see if it's possible to return any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

~~2.2~~2.5 **Requesting Balancing Authority actions.** Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

Rationale for EEA 2: The EOP SDT modified the "Circumstances" for EEA 2 to show that an entity will be in this level when it has implemented its Operating Plan to mitigate Emergencies but is still able to maintain Contingency reserves.

3. EEA 3 —Firm Load interruption is imminent or in progress.

Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinator s and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinator s and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

~~3.1~~**3.2 Declaration Period.** ~~The RC~~The Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the impacted ~~RCs, BAs and TOPs~~Reliability Coordinator s, Balancing Authorities, and Transmission Operators.

~~**2.3 Sharing information on resource availability.** A BA with available resources shall contact the requesting BA and coordinate with the RC as appropriate.~~

~~**2.4 Evaluating and mitigating Transmission limitations.** The RC shall review Transmission outages and work with the TOP to see if it's possible to return the Transmission element that may relieve the Loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).~~

~~2.5~~**2.6 ~~BA actions.~~** ~~Before declaring an EEA 3, the requesting BA must make use of all available resources; this includes, but is not limited to:~~

~~**2.5.1 All available generation units are on line.** All generation capable of being on line in the time frame of the Emergency is on line, including quick-start and peaking units not being held for contingency reserves, regardless of cost.~~

~~**2.5.2 Demand-Side Management curtailed.** Initiate Demand Side Management within provisions of any applicable agreements not being held for contingency reserves.~~

~~**3. EEA 3 — Inability to meet Operating Reserve requirement or Firm Load interruption is imminent or in progress.**~~

~~**Circumstances:**~~

- ~~Requesting BA is unable to meet Operating Reserve requirements and foresees a need for possible interruption of firm Load.~~

~~During EEA 3, RCs and BAs have the following responsibilities:~~

~~**3.2 Continue actions from EEA 2.** The RCs and the requesting BA shall continue to take all actions initiated during EEA 2.~~

~~**3.3 Operating Reserves.** Operating Reserves are being utilized such that the requesting BA is carrying reserves below the required minimum or has initiated Emergency assistance through its Operating Reserve sharing program. In this situation, the requesting BA must be able to shed an amount of firm Load in order to meet its Operating Reserve requirement.~~

~~**3.4 Declaration Period.** The BA shall update its RC of the situation at a minimum of every hour until the EEA 3 is terminated. The RC shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the impacted BAs and TOPs.~~

~~3.5~~3.3 Reevaluating and revising SOLs and IROLs. The ~~RC~~Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the ~~requesting BA.~~energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other ~~RCs~~Reliability Coordinator s and only with the agreement of the ~~TOP~~Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the ~~TOP~~Transmission Operator whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

~~3.5.1~~3.3.1 ~~Requesting BA~~Energy deficient Balancing Authority obligations. The ~~requesting BA must agree that~~energy deficient Balancing Authority, upon notification from its ~~RC~~Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

~~3.6~~3.4 Returning to pre-Emergency conditions. Whenever energy is made available to ~~a requesting BA~~an energy deficient Balancing Authority such that the ~~Transmission~~ Systems can be returned to its pre-Emergency SOLs or IROLs condition, the ~~requesting BA~~energy deficient Balancing Authority shall request the ~~RC~~Reliability Coordinator to downgrade the alert level.

~~3.6.1~~3.4.1 Notification of other parties. Upon notification from the ~~requesting BA~~energy deficient Balancing Authority that an alert has been downgraded, the ~~RC~~Reliability Coordinator shall notify the impacted ~~RCs~~Reliability Coordinator s (via the RCIS), ~~BAs~~Balancing Authorities and ~~TOPs~~Transmission Operators that its Systems can be returned to its normal limits.

Alert 0 - Termination. When the ~~requesting BA~~energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its ~~RC~~Reliability Coordinator to terminate the EEA**.**

0.1 **Notification.** The ~~RC~~Reliability Coordinator shall notify all other ~~RCs~~Reliability Coordinator s via the RCIS of the termination. The ~~RC~~Reliability Coordinator shall also notify the impacted ~~BAs~~Balancing Authorities and ~~TOPs~~Transmission Operators.

Guidelines and Technical Basis

Rationales to be added here after balloting.

Requirement R1:

Requirement R2:

Requirement R3:

Requirement R4:

Requirement R5:

Requirement R6:

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Implementation Plan
Project 2009-03 – Emergency Operations

Standards Involved
Approval:
EOP-011-1 — Emergency Operations

Retirements:
- EOP-001-2.1b — Emergency Operations Planning
- EOP-002-3.1 — Capacity and Energy Emergencies
- EOP-003-2— Load Shedding Plans

Prerequisite Approvals
- PRC-010-1 in Project 2008-02 – Undervoltage Load Shedding

Revisions to the NERC Glossary of Terms
The following term is proposed for revision:

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide its ~~customers'~~ expected ~~energy~~ Load requirements.

Applicable Entities
Reliability Coordinator
Balancing Authority
Transmission Operator

Conforming Changes to Other Standards
Project 2008-02 – Undervoltage Load Shedding (Requirement 1 of PRC-010): Project 2009-03 - Emergency Operations (EOP-011-1) retires EOP-003-2. Requirements R2, R4 and R7 of EOP-003-2, not being absorbed by EOP-011-1, are mapped to PRC-010-1, Requirement 1.

Effective Date
EOP-011-1 and the definition of "Energy Emergency" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard and definition shall

become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

EOP-011-1 is a consolidation of EOP-001-2.1b – Emergency Operations Planning, EOP-002-3.1 – Capacity and Energy Emergencies and EOP-003-2 – Load Shedding Plans. EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 shall retire at midnight of the day immediately prior to the effective date of EOP-011-1 in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan
Project 2009-03 – Emergency Operations

Standards Involved
Approval:
EOP-011-1 —~~-~~ Emergency Operations

Retirements:
- EOP-001-2.1b — Emergency Operations Planning
- EOP-002-3.1 — Capacity and Energy Emergencies
- EOP-003-2— Load Shedding Plans

Prerequisite Approvals
- PRC-010-1 in Project 2008-02 – Undervoltage Load Shedding

Revisions to the NERC Glossary of Terms
The following term is proposed for revision:

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide its ~~customers'~~ expected ~~energy~~ Load requirements.

Applicable Entities
Reliability Coordinator
Balancing Authority
Transmission Operator

Conforming Changes to Other Standards
Project 2008-02 – Undervoltage Load Shedding (Requirement 1 of PRC-010): Project 2009-03 - Emergency Operations (EOP-011-1) retires EOP-003-2. Requirements R2, R4 and R7 of EOP-003-2, not being absorbed by EOP-011-1, are mapped to PRC-010-1, Requirement 1.

Effective Date
EOP-011-1 and the definition of "Energy Emergency" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard and definition shall

become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

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Unofficial Comment Form

Project 2009-03 Emergency Operations

Please **DO NOT** use this form for submitting comments. Please use the electronic form to submit comments on the Standard. The electronic comment form must be completed by **8 p.m. Eastern on Monday, October 20, 2014.**

If you have questions please contact Laura Anderson at laura.anderson@nerc.net or by telephone at 404-446-9671.

Project Page

Background Information

This additional comment period is soliciting formal comment for EOP-011-1.

The Emergency Operations Standard Drafting Team (EOP SDT) merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 to create EOP-011-1. This re-design enables the requirements for Emergency Operations to be streamlined into a clear and concise standard that is organized by Functional Entity in order to eliminate the ambiguity in previous versions. In addition, the revisions clarify the critical requirements for Emergency Operations and apply Paragraph 81 criteria, while making the standard more results-based and address outstanding directives from FERC Order No. 693.

The EOP SDT posted an initial draft of EOP-011-1 for a 30-day informal comment period March 28, 2014 through April 28, 2014. The EOP SDT has considered feedback from the informal comment period, as well as other extensive outreach, and many of the suggested changes were incorporated into the second draft of EOP-011-1. The second draft was posted for formal comment July 2, 2014 through August 15, 2014. The EOP SDT has considered the feedback received from stakeholders during the additional comment period, and a number of changes were made as a result.

Please enter comments in simple text format, **as bullets, numbers, and special formatting will not be retained** (even if it appears to transfer formatting when copying from the unofficial Word version of the form into the official electronic comment form).

- Separate discrete comments by idea, e.g., preface with (1), (2), etc.
- Use brackets [ ] to call attention to suggested inserted or deleted text.
- Insert a "check" mark in the appropriate boxes by double-clicking the gray areas.

- **Do not use** formatting such as extra carriage returns, bullets, automated numbering, symbols, bolding, italics, or any other formatting; this will not be retained when you submit your comments.
- Please do not repeat other entity's comments**.** Select the appropriate item to support another entity's comments. An opportunity to enter additional or exception comments will be available.

Questions

1. **EOP-011-1**. Do you agree with the changes made to EOP-011-1? If not, please specifically identify those changes that you do not agree with, the basis for your disagreement, and your proposed revisions to the language at issue.

   ☐ Yes
   ☐ No

   Comments:

2. **Attachment 1**. Do you agree with the changes made to Attachment 1 of EOP-011-1? If not, please specifically identify those changes that you do not agree with, the basis for your disagreement, and your proposed revisions to the language at issue.

   ☐ Yes
   ☐ No

   Comments:

3. **Violation Risk Factors (VRF) and Violation Severity Levels (VSL)**. The EOP SDT has made revisions to conform with changes to requirements and respond to stakeholder comments. Do you agree with the VRFs and VSLs for EOP-011-1? If you do not agree, please explain why and provide recommended changes.

   ☐ Yes
   ☐ No

   Comments:

4. Are there any other concerns with the proposed standard that have not been covered by previous questions and comments? If so, please provide your feedback to the EOP SDT.

☐ Yes
☐ No

Comments:

Project 2009-03: Emergency Operations

VRF and VSL Justifications for EOP-011-1

VRF and VSL Justifications – EOP-011-1, R1	
Proposed VRF	High
NERC VRF Discussion	Developing, maintaining and implementing a Reliability Coordinator-reviewed Operating Plan to provide the Transmission Operator the means to mitigate operating Emergencies in its Transmission Operator Area. This is a requirement that, if violated, could directly cause or contribute to Bulk Electric System (BES) instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. Since this requirement also is in the Operations Planning time frame, it could, if violated, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures; or could hinder restoration to a normal condition. Since this is a Requirement in a planning time frame, a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation or Cascading failures; or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the Operating Plan and is consistent with Requirement R2.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-003-2 R1, which deals with Load shedding under Emergency conditions, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.

VRF and VSL Justifications – EOP-011-1, R1	
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies in its Transmission Operator Area but failed to maintain it.
Proposed High VSL	The Transmission Operator developed an Operating Plan to mitigate operating Emergencies in its Transmission Operator Area but failed to have it reviewed by the Reliability Coordinator.
Proposed Severe VSL	The Transmission Operator failed to develop an Operating Plan to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies in its Transmission Operator Area but failed to implement it for an operating Emergency.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Operating Plan is not developed, maintained and implemented.

VRF and VSL Justifications – EOP-011-1, R1	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to develop, maintain and implement a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies in its Transmission Operating Area, failing to have it reviewed by the Reliability Coordinator, or failing to implement it for an Operating emergency.

VRF and VSL Justifications – EOP-011-1, R2	
Proposed VRF	High
NERC VRF Discussion	Developing, maintaining and implementing a Reliability Coordinator-reviewed Operating Plan provides the Balancing Authority the means to mitigate Capacity and Energy Emergencies. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. Since this requirement also is in the Operations Planning time frame, it could, if violated, under emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. Since this is a requirement in a planning time frame, a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the Operating Plan and is consistent with Requirement R1.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-003-2 R1, which deals with Load shedding under Emergency conditions, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A .

VRF and VSL Justifications – EOP-011-1, R2	
Proposed Moderate VSL	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies but failed to maintain it.
Proposed High VSL	The Balancing Authority developed an Operating Plan to mitigate operating Emergencies but failed to have it reviewed by the Reliability Coordinator.
Proposed Severe VSL	The Balancing Authority failed to develop an Operating Plan to mitigate operating Emergencies. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies but failed to implement it.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Operating Plan is not developed, maintained and implemented.

VRF and VSL Justifications – EOP-011-1, R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to develop, maintain and implement a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies or failing to have it reviewed by the Reliability Coordinator or failing to implement it for a Capacity or Energy Emergency.

VRF and VSL Justifications – EOP-011-1, R3	
Proposed VRF	Medium
NERC VRF Discussion	Review of an Operating Plan provides the Transmission Operator and Balancing Authority with a Wide Area coordination of their plans. Since this is a requirement in a planning time frame that a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control or restore the BES. However, violation of a medium-risk requirement is unlikely, under Emergency, abnormal or restoration conditions anticipated by the preparations, to lead to BES instability, separation or Cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement specifies that the Reliability Coordinator must review a Transmission Operator's and Balancing Authority's Operating Plans within 30 calendar days of receipt regarding any reliability risks that are identified between Operating Plans. Requirements R1 and R2 specify that the Transmission Operator and Balancing authority must develop, maintain and implement a Reliability Coordinator-reviewed Operating Plan. Requirement R3 ties these three requirements together.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-006-2 R4, which requires the Reliability Coordinator to review neighboring Reliability Coordinator's restoration plans, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

VRF and VSL Justifications – EOP-011-1, R3	
Proposed High VSL	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator within 30 days.
Proposed Severe VSL	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Reliability Coordinator failed to review a Transmission Operator and Balancing Authority Operating Plans that it received regarding any reliability risks that are identified between Operating Plans within the specified time frame.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based	The VSL is assigned for a single instance of failing to review a Transmission Operator and Balancing Authority Operating Plans that it received regarding any reliability risks that are identified between Operating Plans within the specified time frame.

VRF and VSL Justifications – EOP-011-1, R3	
on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – EOP-011-1, R4	
Proposed VRF	High
NERC VRF Discussion	Addressing any reliability risks identified by the Reliability Coordinator during its review Plan provides the Transmission Operator or the Balancing Authority the opportunity to have a Wide-area view of its Operating Plan and to address any risks that it may have overlooked. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. Since this requirement also is in the Operations Planning time frame, it could, if violated, under emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. Since this is a requirement in a planning time frame, a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This requirement specifies that revisions to the Operating Plan be made to address any risks overlooked in the original Operating Plan. This requirement is consistent with Requirements R1 and R2 which requires that the Operating Plan be developed, maintained and implemented.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-003-2 R1, which deals with Load shedding under Emergency conditions, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.

VRF and VSL Justifications – EOP-011-1, R4	
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	The Transmission Operator or Balancing Authority failed to update and resubmit the Operating Plan to the Reliability Coordinator within the timeframe determined by the Reliability Coordinator.
Proposed Severe VSL	The Transmission Operator or Balancing Authority failed to update and resubmit the Operating Plan to the Reliability Coordinator.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Transmission Operator or Balancing Authority failed to update and resubmit the Operating Plan to the Reliability Coordinator within the timeframe determined by the Reliability Coordinator, or if they simply failed to update and resubmit the Operating Plan to the Reliability Coordinator.
FERC VSL G3	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – EOP-011-1, R4	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failure to update and resubmit the Operating Plan to the Reliability Coordinator within the timeframe determined by the Reliability Coordinator, or if they simply failed to update and resubmit the Operating Plan to the Reliability Coordinator.

VRF and VSL Justifications – EOP-011-1, R5	
Proposed VRF	High
NERC VRF Discussion	Notifying Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators of an Emergency helps other entities have proper situational awareness and allows them the opportunity to implement measures to mitigate the Emergency. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement specifies that the Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. This relates to Requirements R1 and R2, whereby the Transmission Operator and the Balancing Authority implement their Operating Plans. These Requirements are all assigned a High VRF.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-011-1 Requirements R1, Part 1.2.1 and Requirement R2, Part 2.2, are assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

VRF and VSL Justifications – EOP-011-1, R5	
Proposed High VSL	The Reliability Coordinator that received an operating Emergency notification from a Transmission Operator or Balancing Authority did notify other Reliability Coordinators, Balancing Authorities and Transmission Operators, but did not notify within 30 minutes from the time of receiving notification.
Proposed Severe VSL	The Reliability Coordinator that received an operating Emergency notification from a Transmission Operator or Balancing Authority and failed to notify other Reliability Coordinators, Balancing Authorities and Transmission Operators.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if a Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, as soon as practical, other impacted Reliability Coordinators, Balancing Authorities and Transmission Operators
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4	The VSL is assigned for a single instance of failing to notifying other entities within 30 minutes of receiving notification.

VRF and VSL Justifications – EOP-011-1, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – EOP-011-1, R6	
Proposed VRF	High
NERC VRF Discussion	Declaration of a potential or actual Energy Emergency alert helps other entities have proper situational awareness and allows them the opportunity to implement measures to mitigate the Energy Emergency. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement and Attachment 1 provide additional detail regarding the initiation of a potential or actual Energy Emergency. This links to Requirement R2, Part 2.2.2 regarding the criteria for an Energy Emergency alert. Both of these Requirements are assigned a High VRF
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-011-1 Requirement R2, Part 2.2.2, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency alert.

VRF and VSL Justifications – EOP-011-1, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area and fails to declare an NERC Energy Emergency alert, as detailed in Attachment 1.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of a Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area and fails to declare an NERC Energy Emergency alert, as detailed in Attachment 1.

Project 2009-03 Emergency Operations (EOP-001-2.1b, -002-3.1, and -003-2)

Consideration of Issues and Directives | July 2014

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
P 571 (S- Ref 10066 – EOP-002) "As we stated in the NOPR, neither EOP-002-2 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies. The Commission agrees with MRO that "insufficient transmission capability" could be due to various causes. The ERO should examine whether to clarify this term in the Reliability Standards development process."	FERC Order No. 693	The EOP SDT has included transmission related items to be included in the Transmission Operator's Emergency Operating Plan. These items impact transmission capability and include Requirement R1, Parts 1.2.2-1.2.5: 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.4. Transmission system reconfiguration; 1.2.5. Redispatch of generation request;
573 (S- Ref 10067 – EOP-003) "The Commission agrees with FirstEnergy that for demand-side resources to qualify as another tool for balancing authorities to use in meeting control performance and disturbance control Reliability Standards, they must meet comparable technical performance requirements as generation resource options. In response to comments from Comverge and APPA, the Commission believes that curtailable loads are adequately addressed in Requirement R6 of	FERC Order No. 693	The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT developed individual requirements for the Transmission Operator and the Balancing Authority to develop, maintain and implement Emergency Operating Plan. The requirements incorporate the applicable elements of Attachment 1 for each entity. **R1.** Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Emergency Operating Plan to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **1.1.** Roles and responsibilities for activating the Operating Plan;

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
the Reliability Standard but that demand response is not covered. Demand response covers considerably more resources than interruptible load. Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements.”		**1.2.** Processes to prepare for and mitigate Emergencies including: **1.2.1.** Notification to the Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; **1.2.2.** Cancellation or recall of Transmission and generation outages; **1.2.3.** Transmission system reconfiguration; **1.2.4.** Redispatch of generation request; **1.2.5.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **1.2.6.** Reliability impacts of extreme weather conditions. **R2.** Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **2.1.** Roles and responsibilities for activating the Operating Plan; **2.2.** Processes to prepare for and mitigate Emergencies including: **2.2.1.** Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; **2.2.2.** Requesting an Energy Emergency Alert, per Attachment 1;

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		2.2.3. Managing generating resources in its Balancing Authority Area to address: **2.2.3.1.** capability and availability; **2.2.3.2.** fuel supply and inventory concerns; **2.2.3.3.** fuel switching capabilities; and **2.2.3.4.** environmental constraints. **2.2.4.** Public appeals for voluntary Load reductions; **2.2.5.** Requests to government agencies to implement their programs to achieve necessary energy reductions; **2.2.6.** Reduction of internal utility energy use; **2.2.7.** Use of Interruptible Load, curtailable Load and demand response; **2.2.8.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **2.2.9.** Reliability impacts of extreme weather conditions.
595 (S- Ref 10072 – EOP-003) "The Commission concludes that the Reliability Standard needs to be modified to ensure that adequate load shedding capabilities are provided so that system	FERC Order No. 693	The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT developed individual requirements for the Transmission Operator and the Balancing Authority to develop, maintain and implement Emergency Operating Plan. The requirements incorporate the applicable elements of Attachment 1 for each entity.

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
operators have an effective operating measure of last resort to contain system emergencies and prevent cascading. The Commission recognizes that the amount of load shedding capability required is dependent on system characteristics and therefore it may not be feasible to have a uniform nationwide load shedding capability. This, however, does not preclude a uniform nationwide criterion on the methodology for establishing load shedding capability that would specify the minimum amount of load shedding capability that should be provided based on system characteristics and conditions and the maximum amount of delay before load shedding can be implemented. The Commission directs the ERO to address the minimum load and maximum time concerns of the Commission through the Reliability Standards development process. We suggest that a review of industry best practices would be useful in developing nationwide critera.		**R1.** Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Emergency Operating Plan to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **1.1.** Roles and responsibilities for activating the Operating Plan; **1.2.** Processes to prepare for and mitigate Emergencies including: **1.2.1.** Notification to the Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; **1.2.2.** Cancellation or recall of Transmission and generation outages; **1.2.3.** Transmission system reconfiguration; **1.2.4.** Redispatch of generation request; **1.2.5.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **1.2.6.** Reliability impacts of extreme weather conditions. **R2.** Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]*

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		2.1. Roles and responsibilities for activating the Operating Plan; **2.2.** Processes to prepare for and mitigate Emergencies including: **2.2.1.** Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; **2.2.2.** Requesting an Energy Emergency Alert, per Attachment 1; **2.2.3.** Managing generating resources in its Balancing Authority Area to address: **2.2.3.1.** capability and availability; **2.2.3.2.** fuel supply and inventory concerns; **2.2.3.3.** fuel switching capabilities; and **2.2.3.4.** environmental constraints. **2.2.4.** Public appeals for voluntary Load reductions; **2.2.5.** Requests to government agencies to implement their programs to achieve necessary energy reductions; **2.2.6.** Reduction of internal utility energy use; **2.2.7.** Use of Interruptible Load, curtailable Load and demand response; **2.2.8.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **2.2.9.** Reliability impacts of extreme weather conditions.

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
P 597 (S- Ref 10073 – EOP-003) “As suggested by California PUC, periodic drills of simulated load shedding should involve all participants required to ensure successful implementation of load shedding plans. As such, the drills should extend beyond system operators to distribution operators and LSEs. The Reliability Standard should require periodic drills by entities subject to section 215, and require those entities to seek participation by other entities. The drills should test the readiness and functionality of the load shedding plans, including, at times, the actual deployment of personnel. Therefore the Commission disagrees with FirstEnergy that the requirement for periodic drills of simulated load shedding should be incorporated into the new PER-005-0 Reliability Standard that is currently being drafted to address operator training.”	FERC Order No. 693	The Transmission Operator participates in Reliability Coordinator restoration drills and they will be able to shed Load with or without the Load-Serving Entity or Distribution Provider. Transmission Operators also participate in annual training required under Reliability Standard PER-005-2. NERC has launched the Risk-Based Registration (RBR) Initiative to ensure that the right entities are subject to the right set of applicable Reliability Standards, using a consistent approach to risk assessment and registration across the ERO. The goal is to develop enhanced registry criteria, including the use of thresholds and specific Reliability Standards applicability, where appropriate, to better align compliance obligations with material risk to Bulk Electric System reliability. The proposed enhancements reduce unnecessary burdens by all involved while preserving Bulk Electric System reliability and avoiding causing or exacerbating instability, uncontrolled separation, or Cascading failures.
P 601 (S- Ref 10074 – EOP-003) “APPA Comments are in Paragraph 598: ‘In addition, APPA states that NERC should consider requiring balancing authorities and	FERC Order No. 693	The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT developed individual requirements for the Transmission Operator and the Balancing Authority to develop, maintain and implement Emergency Operating Plan. The requirements incorporate the applicable elements of Attachment 1 for each entity.

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners'."		Coordination and planning of automatic and manual Load shedding has been adequately addressed by requiring Transmission Operators and Balancing Authorities to have a Reliability Coordinator-reviewed Emergency Operating Plan. **R1.** Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Emergency Operating Plan to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **1.1.** Roles and responsibilities for activating the Operating Plan; **1.2.** Processes to prepare for and mitigate Emergencies including: **1.2.1.** Notification to the Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; **1.2.2.** Cancellation or recall of Transmission and generation outages; **1.2.3.** Transmission system reconfiguration; **1.2.4.** Redispatch of generation request; **1.2.5.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **1.2.6.** Reliability impacts of extreme weather conditions. **R2.** Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **2.1.** Roles and responsibilities for activating the Operating Plan; **2.2.** Processes to prepare for and mitigate Emergencies including: **2.2.1.** Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; **2.2.2.** Requesting an Energy Emergency Alert, per Attachment 1; **2.2.3.** Managing generating resources in its Balancing Authority Area to address: **2.2.3.1.** capability and availability; **2.2.3.2.** fuel supply and inventory concerns; **2.2.3.3.** fuel switching capabilities; and **2.2.3.4.** environmental constraints. **2.2.4.** Public appeals for voluntary Load reductions; **2.2.5.** Requests to government agencies to implement their programs to achieve necessary energy reductions; **2.2.6.** Reduction of internal utility energy use; **2.2.7.** Use of Interruptible Load, curtailable Load and demand response; **2.2.8.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		capable of being implemented in a timeframe adequate for mitigating the Emergency; and **2.2.9.** Reliability impacts of extreme weather conditions. **2.3.**

Proposed Definitions for the NERC Glossary of Terms

Project 2009-03: Emergency Operations

The Emergency Operations Standards Drafting Team (EOP SDT) proposes revisions to a defined term in the NERC Glossary of Terms. This defined term is used in the EOP family of standards and in other standards or defined terms as discussed below.

Proposed revised definitions (redlined):

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer ~~provide~~ meet its ~~customers'~~ expected ~~energy~~ Load ~~requirements~~ obligations.

This defined term was revised to provide clarity that an Energy Emergency is not necessarily limited to a Load-Serving Entity.

This defined term, or variations of it, is also used in the instances below. The EOP SDT does not believe that the proposed revisions change the reliability intent of these standard or definitions.

- **BAL-002-WECC – Contingency Reserve**: This standard becomes enforceable on October 1st, 2014. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **IRO-005-3.1a — Reliability Coordination — Current Day Operations** - This standard was revised under Project 2006-06 and the reference to Energy Emergency was removed from the standard. The standard was approved by the NERC BOT and filed with FERC. NERC has requested that FERC defer action on its petition and is revising this standard under project 2014-03, TOP / IRO Revisions. This project is scheduled to be completed no later than January 31, 2015. The two standard drafting teams are coordinating the definition revision to ensure there are no redundancies.
- **MOD-004-1 — Capacity Benefit Margin:** This standard is being retired and replaced with MOD-001-2 — Modeling, Data, and Analysis — Available Transmission System Capability (NERC BOT approved February 6, 2014). The term "energy emergency" is not used in the new standard. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability to the existing approved standard.
- **INT-004-3 – Dynamic Transfers:** This standard was a revision to INT-004-2 under Project 2008-12. INT-004-3 was approved by the NERC BOT and filed with FERC. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.

- **Defined term Emergency Request for Interchange:** This term is not used in any existing approved standard.

Project 2009-03 - Emergency Operations

Mapping Document

Project Purpose

The Emergency Operations Five-Year Review Team (EOP FYRT) was appointed by the Standards Committee Executive Committee on April 22, 2013. The EOP FYRT has reviewed the following Emergency Operations standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 to decide if revisions are needed in the scope of this project in relation to P81 and FERC directives. This project is a comprehensive review of this set of EOP standards to ensure that the requirements are clear and unambiguous. Many of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process, and the standards were due for a comprehensive review. Suggestions for improvement, possible consolidation and for requirements to be considered for retirement under Paragraph 81 have been submitted by stakeholders, other drafting teams and FERC staff.

On October 17, 2013 the Standards Committee accepted the recommendations of the EOP FYRT and appointed a drafting team to implement the recommendations and begin formal development. The Standards Committee further authorized the posting of the Standard Authorization Request (SAR) developed by the EOP FYRT.

Project 2009-03 – Emergency Operations (EOP-011-1) is being coordinated with Project 2008-02 – Undervoltage Load Shedding, which proposes to retire EOP-003-2 Requirements R2, R4, and R7 since these requirements are proposed to be covered by PRC-010-1, Requirement R1; this translation is illustrated in this document and will also be referenced in Project 2008-02’s mapping document. The project schedules and implementation plans for these two projects are being closely coordinated to ensure that no gaps or duplication will result from the products developed by the two drafting teams.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R2. Each Transmission Operator and Balancing Authority shall: **R2.1.** Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity. **R2.2.** Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system. **R2.3.** Develop, maintain, and implement a set of plans for load shedding	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan; 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to the Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include: **R3.1.** Communications protocols to be used during emergencies. **R3.2.** A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within	Translated to EOP-011-1, Emergency Operations; Retired R3.1 under Criteria A and B7 of Paragraph 81 guidelines; Retired R3.4 under Criteria A and B1 of	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
NERC-established timelines, shall be one of the controlling actions. **R3.3.** The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities. **R3.4.** Staffing levels for the emergency.	Paragraph 81 guidelines.	1.1. Roles and responsibilities for activating the Operating Plan; 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to the Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2**

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		<u>**Retirements:**</u> **Requirement R3.1** • Meets Criterion B7 and Criterion A of Paragraph 81; • Covered by EOP-001-2.1b Requirement R4 in Attachment 1 (proposed Requirements R1 and R2 in EOP-011-1); and • COM-001 and COM-002 are descriptive in the identification of protocols to use and, thus, adequately cover the generic reference. **Requirement R3.2** • Meets Criterion B7 and Criterion A of Paragraph 81; and • Load reduction within timelines is covered by BAL-002 Requirement R2. **Requirement R3.4** • Meets Criterion B1 of Paragraph 81; and • Staffing levels are administrative in nature.
R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in		**EOP-011-1, R1**

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Attachment 1-EOP-001 when developing an emergency plan.	Translated to EOP-011-1, Emergency Operations.	R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan; 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to the Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan; 1.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.1. Notification to the Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan to the Reliability Coordinator within a time period specified by its Reliability Coordinator. [Violation Risk Factor: High] [Time Horizon: Operation Planning]
R6. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable: **R6.1.** The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems. **R6.2.** The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used. **R6.3.** The Transmission Operator and Balancing Authority shall coordinate transmission	Retired under Criteria B6 and B7 of P81 guidelines.	<u>**Retirements**</u> **Requirement R6.1** • Meets Criterion B7 of Paragraph 81; and • Redundant with COM-001. **Requirement R6.2** • Meets Criterion B6 of Paragraph 81; • Speaks to an action to be taken during capacity issues that is not feasible in accomplishing; and • Transaction arrangements are a commercial practice. **Requirement R6.3** • Meets Criterion B7 of Paragraph 81; and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.) **R6.4.** The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.		• Covered by EOP-001-2.1b Requirement R4 in Attachment 1 (proposed Requirements R1 and R2 in EOP-011-1). **Requirement R6.4** • Meets Criterion A of Paragraph 81; and • Does not provide benefit to the reliability of the BES.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall	Retired under Criteria A and B7 of P81 guidelines.	**Retired – redundant with PER-001, R1 with respect to the Balancing Authority and IRO-001-1.1, Requirement R3 for the Reliability Coordinator.**

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
exercise specific authority to alleviate capacity and energy emergencies.		
R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan to reduce risks to the interconnected system.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*
R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions		**EOP-011-1, R2**

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.	Translated to EOP-011-1, Emergency Operations.	R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: **R6.1.** Loading all available generating capacity. **R6.2.** Deploying all available operating reserve. **R6.3.** Interrupting interruptible load and exports. **R6.4.** Requesting emergency assistance from other Balancing Authorities. **R6.5.** Declaring an Energy Emergency through its Reliability Coordinator; and **R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall: **R7.1.** Manually shed firm load without delay to return its ACE to zero; and **R7.2.** Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R6** R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration transmission Service from designated Network Resources) as permitted in its transmission tariff: **R9.1**. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts." **R9.2.** The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed. **R9.3.** The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.	Retired per P81 – this is addressed in NAESB tagging specification.	**LSEs have no Real-time reliability functionality with respect to EEAs.** Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R9.4. The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.		
Attachment 1 **2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.	Translated to EOP-011-1, Attachment 1.	**Attachment 1EEA 2 – Load management procedures in effect** • An energy deficient BA is still able to maintain minimum Contingency Reserve requirements.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan; 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to the Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.	EOP-003-2, R2 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term*

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
	responsible for the program design.	*Planning]* **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design. **1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
plans, among other interconnected Transmission Operators and Balancing Authorities.		reviewed Operating Plan to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan; 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to the Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels.	EOP-003-2, R4 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design. EOP-003-2, R4 is inherently embedded in PRC-010-1, R1, Part 1.1. The specific items	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
	noted are described in PRC-010-1's Guidelines and Technical Basis.	**1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.	Retired under Criteria A and B7 of Paragraph 81.	**Redundant with R1 of EOP-003-2, which maps to EOP-011-1, R1.** Requirement R5 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.	Retired under Criteria and B7 of Paragraph 81.	**Redundant with R1 of EOP-003-2, which maps to EOP-011-1, R1.** Requirement R6 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R6 speaks of two events that must be valid to tell the BA or TOP to shed more Load. .
R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions.	EOP-003-2, R7 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design. EOP-003-2, R7 is inherently embedded in PRC-010-1, R1, Part 1.2.	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
	The specific items noted are described in PRC-010-1's Guidelines and Technical Basis.	**1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan; 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to the Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		EOP-011-1, R2 R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to the Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**

Technical Justification
EOP-011-1 Emergency Operations and Planning

Background and Rationale for revisions of EOP-001-2.1b, EOP-002-3.1 and EOP-003-2

Purpose

The purpose of EOP-011-1 is to mitigate the effects of operating Emergencies, up to and including manual Load shedding, by implementing Emergency Operating Plans. The standard streamlines the requirements for Emergency Operations for the BES into a clear and concise standard that is organized by Functional Entity in order to eliminate ambiguity. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

The requirements of the proposed EOP-011-1 reliability standard support the following Reliability Principles:

> Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
>
> The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
>
> Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
>
> Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

EOP-011-1 consolidates requirements from three existing Emergency Operations standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2. The table *Elements for Consideration in Development of Emergency Plans* from Attachment 1 of EOP-001-2.1b were considered by the EOP SDT and incorporated into the requirements of proposed EOP-011-1.

The Project 2009-03 Emergency Operations Standard Drafting Team (EOP SDT) developed EOP-011-1 by considering the following inputs:

- Applicable FERC directives;
- Five Year Review Team (FYRT) recommendations;
- Independent Expert Review Panel recommendations; and
- Paragraph 81 criteria.

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History and Inputs to Project 2009-03 Emergency Operations

Periodic Review of EOP Standards

The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every 10 years, or once every five years for any Reliability Standard approved by the American National Standards Institute as an American National Standard.[1] The Emergency Operations Five-Year Review Team (EOP FYRT) was appointed by the Standards Committee Executive Committee on April 22, 2013. The EOP FYRT reviewed the following Emergency Operations standards: EOP-001-2.1b (Emergency Operations Planning), EOP-002-3.1 (Capacity and Energy Emergencies) and EOP-003-2 (Load Shedding Plans) to determine if the standards should be retained, retired or if revisions were needed in the scope of this project in relation to P81 criteria, Independent Expert report and FERC directives.

The scope of the review included consideration of recommendions from the Industry Expert Review Panel report, Paragraph 81 recommendations and criteria, and outstanding FERC Order No. 693 directives, as well as industry comments. The EOP FYRT posted its draft recommendations to revise the standards for stakeholder comment. After reviewing stakeholder comments, the EOP FYRT submitted its final recommendations to the Standards Committee, along with a Standard Authorization Request (SAR). This SAR replaces an earlier SAR, and the new SAR provided the scope for the work of Project 2009-03. The EOP SDT implemented the FYRT recommendations into proposed reliability standard EOP-011-1.

Industry Expert Report2

In 2013 NERC assembled a panel of Industry Experts (the IERP) to review all reliability standards and provide recommendations for consideration in the transition of NERC standards to steady state. For the Emergency Operations and Planning reliability standards, the Industry Experts made the following recommendations:

- EOP-001-2.1b, R6 - P81. Duplicative of R4 and the Attachment
- EOP-002-3.1, R2 - P81. Duplicative - requirement to take action is in R1.
- EOP-002-3.1, R3 - P81. Duplicative of what is required to be in the plan under Attachment 1 of EOP-001.
- EOP-002-3.1, R6 -P81. Duplicative of BAL standards to meet CPS and DCS
- EOP-002-3.1, R9 - P81. This is a market (tariff) issue.
- EOP-003-2, R2 - P81. Duplicative of PRC-010 and TPL standards
- EOP-003-2, R4 - P81. Duplicative of PRC-010 and TPL standards
- EOP-003-2, R5 - P81. Duplicative of R1 and also covered under standards for TOP (TOP-002-3)
- EOP-003-2, R6 - P81. Duplicative; an entity does the same actions as when not islanded.

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[1] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf

[2] NERC Standards Independent Expert Review Project, An Independent Review by Industry Experts, posted at http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf

- EOP-003-2, R7 - P81. Duplicative of PRC-010 R1

As part of the EOP Five-Year Review process, the EOP FYRT evaluated these recommendations and generally agrees with them, with exceptions and further considerations for the standard drafting team, as noted below:

- EOP-001-2.1b - the EOP FYRT concurred with the recommendation to retire R6 in accordance with the applicable Paragraph 81 criteria (Requirements 6.1 and 6.3 under Criterion B7; Requirement R6.2 under Criterion B6; and Requirement R6.4 under Criterion A). In addition, the EOP FYRT also recommended that the future EOP SDT take into consideration retiring Requirements R3.1 under Criterion B7, Requirement R3.2 under Criterion B7 and Criterion A, and Requirement R3.4 under Criterion B1 of Paragraph 81. The EOP FYRT further recommended revising and merging EOP-001-2.b and EOP-002-3.1 into a single standard; revising Requirements R1, R2 and R5 and reviewing Attachment 1.
- EOP-002-3.1 - in addition to Requirements R6 and R9, the EOP FYRT recommended retiring Requirements R1 under Criterion B7 of Paragraph 81. The EOP FYRT further recommended that the future EOP SDT consider revising and merging EOP-001-2.b and EOP-002-3.1 into a single standard, which would include a revision to Requirement R3 and Attachment 1.
- EOP-003-2 - the EOP FYRT recommended Requirements R2, R4 and R7 be moved to PRC-010-0 and revised in accordance with the other requirements in that standard. In addition to merging EOP-001-2.1b with EOP-002-3.1, the EOP FYRT recommended the future EOP SDT consider merging EOP-003-2, EOP-001-1-2.1b and EOP-002-3.1 into a single standard.

Paragraph 81[3]

For a reliability standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy both: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B (identifying criteria). In addition, for each reliability standard requirement proposed for retirement or modification, the data and reference points of Criterion C should be considered for making a more informed decision.

Paragraph 81 recommendations from the Independent Experts and Industry were reviewed and the EOP SDT incorporated those into the development of EOP-011-1.

FERC Directives

In the development of the proposed EOP-011-1 reliability standard, the EOP SDT addressed the outstanding FERC directives in Order No. 693 related to Emergency Operations and planning4. Briefly, the directives applicable to each standard are listed below:

[3] NERC – Paragraph 81 Criteria posted at http://www.nerc.com/pa/stand/project%20200812%20coordinate%20interchange%20standards%20dl/paragraph_81_criteria.pdf
[4] Outstanding FERC Order 693 directives listing related to Emergency Operations posted at Project 2009-03 Directives.xlsx

EOP-001-1 Emergency Operations Planning:

- Include reliability coordinators as an applicable entity.
- Consider Southern California Edison's and Xcel's suggestions in the standard development process.
- Clarify that the 30-minute requirement in requirement R2 to state that Load shedding should be capable of being implemented as soon as possible but no more than 30 minutes.
- Includes definitions of system states (e.g. normal, alert, emergency), criteria for entering into these states. And the authority that will declare them.
- Consider a pilot program (field test) for the system states proposal.
- Clarifies that the actual emergency plan elements, and not the "for consideration" elements of Attachment 1, should be the basis for compliance.

EOP-002-2 Capacity and Energy Emergencies:

- Address emergencies resulting not only from insufficient generation but also insufficient.
- Transmission capability, particularly as it affects the implement of the capacity and energy
- Emergency plan.
- Include all technically feasible resource options, including demand response and generation resources.
- Ensure the TLR procedure is not used to mitigate actual IROL violations.

EOP-003-1 Load Shedding Plans:

- Develop specific minimum Load shedding capability that should be provided and the maximum amount of delay before Load shedding can be implemented based on overarching nationwide criteria that take into account system characteristics.
- Require periodic drills of simulated Load shedding.
- Suggest a review of industry best practices in determining nationwide criteria.
- Consider comments from APPA and ISO-NE in the standards development process.

Rationales for Requirements

Proposed reliability standard EOP-011-1 merges EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 into a single standard applicable to the following functional entities:

- Balancing Authority
- Reliability Coordinator
- Transmission Operator

Requirement R1:

The EOP SDT examined the recommendation of the EOP FYRT and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT identified that in Attachment 1 there are elements that would not relate to the Transmission Operator and removed them from this requirement. These elements were listed in the original standard and have been retained in this standard. This also establishes a requirement for the Transmission Operator to create its Emergency Operating Plan to address capacity and energy Emergencies.

Requirement R2:
As with Requirement R1, the EOP SDT took the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1 as it relates to the Balancing Authority. The EOP SDT identified that in Attachment 1 there are elements that would not relate to the Balancing Authority and removed them from this requirement. These elements were listed in the original standard and have been retained in this standard. This also establishes a requirement for the Balancing Authority to create its Emergency Operating Plan to address capacity and energy Emergencies.

Requirement R3:
The EOP SDT agrees that Transmission Operators and Balancing Authorities should submit Emergency Operating plans to the Reliability Coordinator for approval in order for the Reliability Coordinator to ensure all Emergency Operating Plans in its Reliability Coordinator Area exist. The EOP SDT also has created this requirement so that it is similar in structure to the EOP-006-2, Requirement 5.1. The Requirement reflects the directive of the Federal Energy Regulator Commission to have the Reliability Coordinator involved in the Operating Plans of the Transmission Operator and Balancing Authority.

"…the Commission finds the reliability coordinator is a necessary entity under EOP-001-0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity."

Requirement R4:
The EOP SDT added the words "as soon as practical" to the requirement to point to the timeliness and to the relevancy of the Emergencies and to alleviate excessive notifications on Balancing Authorities and Transmission Operators. This was an existing requirement in EOP-002-3.1 for Balancing Authorities.

Requirement R5:
The EOP SDT retained Requirement R8 from E0P-002-3.1. The Load-Serving Entity has the right, under Attachment 1, to request that an Energy Emergency Alert (EEA) be issued, but it does not have any requirements to do so; therefore, the EOP SDT elected to remove the Load-Serving Entity in the requirement. The EOP SDT also ensured Requirement R5 was created to address the FERC directive to have the Reliability Coordinator involved to ensure that the Energy Emergency Alert gets initiated.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Emergency Operations (EOP-001-3, EOP-002-4, EOP-003-3)		
Date Submitted:	October 17, 2013		
SAR Requester Information			
Name:	David McRee, Chair EOP Five-Year Review Team (FYRT)		
Organization:	Duke Energy		
Telephone:	(704) 382-9841	E-mail:	David.McRee@duke-energy.com
SAR Type (Check as many as applicable)			
☐ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
This SAR will address the Five-Year Review requirement for these standards.
Purpose or Goal (How does this request propose to address the problem described above?):
To improve the quality, relevance, and clarity of the standards. Also bring the standards into the Results Based Standards format.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
To increase the effectiveness of the three standards in their ability to ensure reliability of the BES.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The EOP SDT will consider the comments received from the EOP Five Year Review Team (FYRT), which includes consideration of industry comments and the report from the Industry Expert Review Panel. Recommendations for consideration are: • Modify the requirements and attachments to improve their clarity and measurability, while removing ambiguity • Move and/or streamline requirements • Eliminate requirements based on P81 criteria • Coordinate with Project 2008-02 UVLS to eliminate duplicative requirements • Apply Paragraph 81 criteria and recommendations from Independent Expert Review Panel on standards EOP-001, -002, and -003. To ensure a seamless transition from the EOP FYRT to the future EOP SDT, the EOP FYRT recommends the inclusion of interested EOP FYRT members to participate on the EOP SDT. In addition, the EOP FYRT should provide a high-level overview of their recommendations as a formal kick-off to the future EOP SDT meetings.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
See the attached Five-Year Review templates of the three standards, consideration of comments, issues and directives list, redlined standards (reflecting deletions), and the Industry Experts' anyalsis.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☒ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

Reliability Functions		
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards

Related Standards	
Standard No.	**Explanation**
BAL-001-0.1a	Real Power Balancing Control Performance
BAL-002-01	Disturbance control standard
BAL-002-WECC	Regional Contingency Reserve standard
COM-001-1.1	Telecommunications
COM-002-2	Communications and Coordination
PRC-010-0	Planning for Undervoltage Load shedding
PER-005-1	Training

Related SARs	
SAR ID	**Explanation**
	None

Regional Variances	
Region	**Explanation**
ERCOT	

Regional Variances	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

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Five-Year Review Template – EOP-001-2.1b

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-001-2.1b Emergency Operations Planning
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111, ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:
   Requirement R3:

   - Requirement R3.1 should be covered by EOP-001-2.1b Requirement R4 in Attachment 1 (notifications that should be included in the plan are identified). COM-001 and COM-002 are descriptive in the identification of protocols to use and, thus, adequately cover the generic reference. With the recommended revision to Attachment 1 of EOP-001-2.1b, along with COM-001 and COM-002 generic reference, Requirement R3.1 would meet Criterion B7 as redundant, as well as Criterion A (Requirement R3.1 does little, if anything, to benefit or protect the reliable operation of the BES) of Paragraph 81 and should be retired.
   - Requirement R3.2 should be covered by EOP-001-2.1b Requirement R4 in Attachment 1, which lists the actions to take during capacity situations specified in the plan. Load reduction within timelines is covered in BAL-002 Requirement R2. With the recommended revision of EOP-001 Requirement R4, Requirement R3.2 would meet Criterion B7 as redundant, as well as Criterion A (R3.1 does little, if anything, to benefit or protect the reliable operation of the BES) of Paragraph 81 and should be retired.
   - Requirement R3.4 meets Paragraph 81 Criterion B1; staffing levels are administrative in nature and would result in an increase in efficiency in the ERO compliance program (it is a simple check off during an audit). Requirement R3.4 also meets with Criterion A of Paragraph 81, as a check-off does not enhance the reliability of the BES. Requirement R3.4 should be retired as falling under Criterion B1 and Criterion A of Paragraph 81.

   Requirement 6 in its entirety:

   - Requirement R6.1 is redundant with COM-001, meeting Criterion B7 as redundant under Paragraph 81 and should be retired.
   - Requirement R6.2 speaks to an action to be taken during capacity issues that is not feasible in accomplishing. Transaction arrangements are also a commercial practice and, thus, Requirement R6.2 meets Criterion B6 of Paragraph 81 and should be retired.

- Requirement R6.3 is redundant with EOP-001-2b Requirement R4 and Attachment 1, whereby meeting Criterion B7 as redundant under Paragraph 81 and should be retired.
- Requirement R6.4 does not provide for benefit for reliability of the BES, meeting Criterion A of Paragraph 81 and should be retired.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

    a. Is this a Version 0 Reliability Standard?
    b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
    c. Are the requirements consistent with the purpose of the Reliability Standard?

    ☒ Yes

    ☐ No

    Please summarize your assessment:
    The 2009-03 Emergency Operations Five-Year Review Team (EOP FYRT) recommends that EOP-001-2.b and EOP-002-3.1 be revised and merged into a single standard identifying clearly and separately the Transmission Operator, Generation Operator and Reliability Coordinator issues as they relate to the BA and TOP (to address Paragraph 548 of Order 693) and how it needs to be planned and implemented for on the BES by the specific functional entities.

    - Requirement R1 needs clarity provided as to what an operating agreement constitutes, and adjust the VSL to reflect current interpretations with the number of agreements needed. Requirement R1 must also account for current interpretations found in the Appendix and other interpretations.
    - Requirement R2 needs clarity provided, as instructed by the Commission, on the ambiguity of the EOP standards as they relate to the responsibilities of the Transmission Operator and Balancing Authority.
    - Requirement R5, the need to share emergency plans with neighboring Transmission Operators and Balancing Authorities, should be removed as an administrative burden (identified in P81); however, the remaining language of the requirement should be affirmed.
    - Review is recommended for Attachment 1 as it relates to the GOP in light of recent BES events (Cold Weather Event).

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☒ Yes

☐ No

Please explain:
Appendix 1 attempts to define what a remote Balancing Authority is and should be addressed in future revisions of the Standard

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

   Additional measures must be provided with this standard. There are no performance measures. There are no VRFs with this standard. Requirement R1, once recommended clarity is provided as to what an operating agreement constitutes, adjustment to the VSL will be necessary to reflect current interpretations with the number of agreements needed.

☐ Yes

☒ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

☐ Yes

☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

☐ Yes

☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

NERC

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE – Requirement R1, R2, R5 and Attachment 1

☒ RETIRE – Requirements R3.1, R3.2, R3.4, R6.1, R6.2, R6.3, R6.4

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE – Requirements R1, R2, R5 and Attachment 1

☒ RETIRE – Requirements R3.1, R3.2, R3.4; Requirement R6 in its entirety; R6.1, R6.2, R6.3, R6.4

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

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Five-Year Review Template – EOP-002-3

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-002-3.1 Capacity and Energy Emergencies
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111,ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   - Requirement R1 is redundant with IRO-001 and PER-001-2 and should be retired under Criterion B7 of Paragraph 81.
   - Requirement R6 is redundant with BAL-002-1a and should be retired under Criterion B7 of Paragraph 81.
   - Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR, and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired. Due to the retirement of R9, LSE applicability should be removed in the standard.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

Please summarize your assessment:
The EOP FYRT recommends that EOP-001-2b and EOP-002-3.1 be revised and merged into a single standard to address redundancy in the stating that a plan should be implemented. Both standards are different enough that those requirements not identified in retirement recommendations under Paragraph 81 should be retained.

Requirement R8 and Attachment 1 have several issues regarding applicability to different functions and should be revised to eliminate discrepancies and for clarity. Attachment 1 needs to be reviewed for consistency with IRO and TOP standards. The EOP FYRT recommends review of the uniqueness as it relates to ERCOT and similarly situated BAs. The EOP FYRT recommends the future EOP SDT address the directive in Paragraph 573 of Order 693.

The EOP FYRT further recommends a language change in Requirement R2, replacing "interconnected system" with "Bulk Electric System." Requirements R3 and R4 need to be reviewed by the future EOP SDT to further define the word "emergency" (as Capacity Emergency, Emergency, and Energy Emergency are already NERC defined terms). The EOP FYRT recommends the following sentence in Requirement R5 to be struck: "Such unilateral adjustment may overload transmission facilities."

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes

☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

☒ Yes

☐ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or

consistency with other Reliability Standards? If you answered “Yes,” please describe the changes needed to achieve formatting and language consistency:

☐ Yes

☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered “Yes,” please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised: Requirement R9 (recommended for retirement under Paragraph 81) the TSP now has the ability to change the Transmission priority, which is in turn reflected in the IDC.

   ☒ Yes

   ☐ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE (and merge with EOP-001-2b)

☒ RETIRE – Requirements R1, R6 and R9 in its entirety.

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE (and merge with EOP-001-2b); Requirement R2, replacing “interconnected system” with “Bulk Electric System;” language revision in Requirement R2; Requirements R3 and R4 need to be reviewed by the future EOP SDT to further define the word “emergency” (as Capacity Emergency, Emergency, and Energy Emergency are already NERC defined terms); Requirement R5, strike “Such unilateral adjustment may overload transmission facilities.”

☒ RETIRE – Requirements R1, R6, and R9 in its entirety. Due to the retirement of R9, LSE applicability should be removed in the standard.

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant

The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board (“NAESB”), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)

Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?

The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?

The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection (“CIP”) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?

The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Five-Year Review Template – EOP-003-2

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-003-2 Load Shedding Plans
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111, ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   - Requirements R5 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R5 speaks to shedding loads in steps; that same process will be done in Requirement R1. Requirement R5 should be retired under Criterion B7 of Paragraph 81.
   - Requirements R6 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R6 speaks of two events that must be valid to tell the BA or TOP to shed more load, but overall the action of shedding load to meet insufficient generation is the same as stated in Requirement R1. Requirement R6 should be retired under Criterion B7 of Paragraph 81.
   - EOP-003-2– Recommend that Requirements R2, R4 and R7 be moved to PRC-010-0 or otherwise addressed during Project 2008-02 – Undervoltage Load Shedding.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

Please summarize your assessment:
The EOP FYRT team believes that Requirements R2, R4 and R7 should be coordinated with the revision of PRC-010 (Project 2008-02 Undervoltage Load Shedding) for inclusion in that standard. This is consistent with the review that was done for automatic underfrequency requirements and should also be performed for automatic undervoltage requirements.

Based on the recommendations received during the comment period, EOP FYRT further recommends R1 and R8 be considered to be combined. The EOP FYRT also received comments that EOP-003-2 should be combined with EOP-001-2.1b and EOP-002-3.1, and the EOP FYRT recommends this be evaluated in the SAR. In addition, the EOP FYRT recommends that the future EOP SDT evaluate the separation of the functional entity capabilities of the BA and the TOP responsibilities.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes

☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

The Measures and Data retention should be reviewed and updated

☐ Yes

☒ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

☐ Yes

☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☐ Yes

   ☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE – Retire Requirements R5, R6, R2, R4 and R7 and address directives in Paragraphs 595 and 603 of Order 693

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*: See responses to questions 1, 2, and 4 above.

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE - Retire Requirements R5, R6, R2, R4 and R7 and address directives in Paragraphs 595 and 603 or Order 693; recommend for consideration Requirements R1 and R8 be combined; consider combining EOP-003-2 with EOP-001-2.1b and EOP-002-3.1; evaluate the separation of the functional entity capabilities of the BA and TOP responsibilities.

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

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[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant

The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)

Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?

The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?

The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?

The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Proposed Definitions for the NERC Glossary of Terms

Project 2009-03: Emergency Operations

The Emergency Operations Standards Drafting Team (EOP SDT) proposes revisions to a defined term in the NERC Glossary of Terms. This defined term is used in the EOP family of standards and in other standards or defined terms as discussed below.

Proposed revised definitions (redlined):

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer ~~provide~~ meet its ~~customers'~~ expected ~~energy~~ Load ~~requirements~~ obligations.

This defined term is being proposed for revision to provide clarity that an Energy Emergency is not necessarily limited to a Load-Serving Entity.

This defined term, or variations of it, are also used in the instances below. The EOP SDT does not believe that the proposed revisions change the reliability intent of other requirements or definitions.

- **BAL-002-WECC – Contingency Reserve**: This standard becomes enforceable on October 1, 2014. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **IRO-005-3.1a — Reliability Coordination — Current Day Operations** - This standard was revised under Project 2006-06 and the reference to Energy Emergency was removed from the standard. The standard was approved by the NERC BOT and filed with FERC. NERC has requested that FERC defer action on its petition and is revising this standard under Project 2014-03, TOP / IRO Reliability Standards. This project is scheduled to be completed no later than January 31, 2015. The two standard drafting teams are coordinating the definition revision to ensure there are no redundancies.
- **MOD-004-1 — Capacity Benefit Margin:** This standard is being retired and replaced with MOD-001-2 — Modeling, Data, and Analysis — Available Transmission System Capability (NERC BOT approved February 6, 2014). The term "Energy Emergency" is not used in the new standard. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability to the existing approved standard.
- **INT-004-3 – Dynamic Transfers:** This standard was a revision to INT-004-2 under Project 2008-12. INT-004-3 was approved by the NERC BOT and filed with FERC. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.

- **Defined term Emergency Request for Interchange:** This term is not used in any existing approved standard.

Proposed Definitions for the NERC Glossary of Terms

Project 2009-03: Emergency Operations

The Emergency Operations Standards Drafting Team (EOP SDT) proposes revisions to a defined term in the NERC Glossary of Terms. This defined term is used in the EOP family of standards and in other standards or defined terms as discussed below.

Proposed revised definitions (redlined):

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer ~~provide~~ meet its ~~customers'~~ expected ~~energy~~ Load ~~requirements~~ obligations.

This defined term ~~was~~ is being proposed for ~~revised~~ revision to provide clarity that an Energy Emergency is not necessarily limited to a Load-Serving Entity.

This defined term, or variations of it, ~~is~~ are also used in the instances below. The EOP SDT does not believe that the proposed revisions change the reliability intent of ~~these~~ other ~~standard~~ requirements or definitions.

- **BAL-002-WECC – Contingency Reserve**: This standard becomes enforceable on October 1st, 2014. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **IRO-005-3.1a — Reliability Coordination — Current Day Operations** - This standard was revised under Project 2006-06 and the reference to Energy Emergency was removed from the standard. The standard was approved by the NERC BOT and filed with FERC. NERC has requested that FERC defer action on its petition and is revising this standard under ~~project~~ Project 2014-03, TOP / IRO ~~Revisions~~Reliability Standards. This project is scheduled to be completed no later than January 31, 2015. The two standard drafting teams are coordinating the definition revision to ensure there are no redundancies.
- **MOD-004-1 — Capacity Benefit Margin:** This standard is being retired and replaced with MOD-001-2 — Modeling, Data, and Analysis — Available Transmission System Capability (NERC BOT approved February 6, 2014). The term "~~energy~~ Energy ~~emergency~~Emergency" is not used in the new standard. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability to the existing approved standard.

- **INT-004-3 – Dynamic Transfers:** This standard was a revision to INT-004-2 under Project 2008-12. INT-004-3 was approved by the NERC BOT and filed with FERC. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **Defined term Emergency Request for Interchange:** This term is not used in any existing approved standard.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Standard Audit Worksheet[1]

EOP-011-1 – Emergency Operations

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1													X		
R2	X														
R3									X						
R4	X												X		
R5									X						
R6									X						

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

__Findings__

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			
R6			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable:

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

1.2.6. Reliability impacts of extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

Registered Entity Response (Required):
Question: Has there ever been an Emergency where the Transmission Operator's Operating Plan(s) has been implemented to mitigate operating Emergencies during the compliance monitoring period? ☐ Yes ☐ No
If Yes, provide a list of such Emergencies.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below. An entity may have combined plans as a Transmission Operator and Balancing Authority.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
Documented plan(s).
Evidence of activation, such as operator logs, voice recordings, or other communications, for times when an

Emergency has occurred.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R1

This section to be completed by the Compliance Enforcement Authority

	(R1) Confirm the plan(s) is dated and reviewed by its Reliability Coordinator.
	(R1) Confirm the plan(s) was developed in accordance with Requirement R1 and includes processes for the following as applicable:
	(Part 1.1) Roles and responsibilities for activating the Operating Plan(s);
	(Part 1.2.1) Notification of its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;
	(Part 1.2.2) Cancellation or recall of Transmission and generation outages;
	(Part 1.2.3) Transmission system reconfiguration;
	(Part 1.2.4) Redispatch of generation;
	(Part 1.2.5) Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency;
	(Part 1.2.6) Reliability impacts of extreme weather conditions.
	(R1) Verify implementation of plan(s). (see note below)
Note to Auditor: Auditors can gain reasonable assurance the plan(s) was implemented by determining if specific actions prescribed by the plan(s) have taken place. For example, if the plan(s) calls for certain processes to occur, then auditors could ask for evidence demonstrating the process has been implemented. As auditors should obtain reasonable, not absolute, assurance the plan(s) was implemented, testing implementation on a sample basis may be appropriate.	

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable:

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

2.2.9. Reliability impacts of extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

Registered Entity Response (Required):

Question: Has there ever been an Emergency where the Balancing Authority's Operating Plan(s) has been implemented to mitigate Capacity Emergencies and Energy Emergencies during the compliance monitoring period? ☐ Yes ☐ No

If Yes, provide a list of such Emergencies.

[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below. An entity may have combined plans as a Transmission Operator and Balancing Authority.]

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
Documented plan(s).
Evidence of activation, such as operator logs, voice recordings, or other communications, for times when an Emergency has occurred.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R2

This section to be completed by the Compliance Enforcement Authority

	(R2) Confirm the plan(s) is dated and reviewed by its Reliability Coordinator.
	(R2) Confirm the plan(s) was developed in accordance with Requirement R2 and includes processes for the following as applicable:
	(Part 2.1.) Roles and responsibilities for activating the Operating Plan(s);
	(Part 2.2) Processes to prepare for and mitigate Emergencies including:
	(Part 2.2.1) Notification of its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;
	(Part 2.2.2) Requesting an Energy Emergency Alert, per Attachment 1;
	(Part 2.2.3) Managing generating resources in its Balancing Authority Area to address:
	(Part 2.2.3.1) capability and availability;
	(Part 2.2.3.2) fuel supply and inventory concerns;
	(Part 2.2.3.3) fuel switching capabilities; and
	(Part 2.2.3.4) environmental constraints.

	(Part 2.2.4) Public appeals for voluntary Load reductions;
	(Part 2.2.5) Requests to government agencies to implement their programs to achieve necessary energy reductions;
	(Part 2.2.6) Reduction of internal utility energy use;
	(Part 2.2.7) Use of Interruptible Load, curtailable Load and demand response;
	(Part 2.2.8) Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and
	(Part 2.2.9) Reliability impacts of extreme weather conditions.
	(R2) Verify implementation of plan(s). (see note below)

Note to Auditor:

Auditors can gain reasonable assurance the plan(s) was implemented by determining if specific actions prescribed by the plan(s) have taken place. For example, if the plan(s) calls for certain processes to occur, then auditors could ask for evidence demonstrating the process has been implemented. As auditors should obtain reasonable, not absolute, assurance the plan(s) was implemented, testing implementation on a sample basis may be appropriate.

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans.

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated e-mails or other correspondences that it reviewed Transmission Operator and Balancing Authority Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
The Reliability Coordinator will have documentation, such as dated e-mails or other correspondence that it reviewed Transmission Operator and Balancing Authority Operating Plans within 30-calendar days of submittal in accordance with Requirement R3.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R3

This section to be completed by the Compliance Enforcement Authority

	(R3) Through the review of submitted evidence and interviews with entity representatives, confirm that the Reliability Coordinator reviews plans within 30-calendar days.
Note to Auditor:	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator.

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

Registered Entity Response (Required):
Question: Did entity's Reliability Coordinator identify any reliability risks associated with entity's Operating Plan(s) during the compliance monitoring period?
☐ Yes ☐ No
If Yes, provide a list of notifications. If auditor is reasonably assured of entity's No answer, then no further audit testing of Requirement R4 is necessary.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
Dated correspondence between the entity and Reliability Coordinator regarding revisions to the entity's Operating Plan(s) based on reliability risks identified by the Reliability Coordinator.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R4

This section to be completed by the Compliance Enforcement Authority

	(R4) Review evidence and verify the entity resubmitted its Operating Plan to its Reliability Coordinator within the time period specified by the Reliability Coordinator in instances where the Reliability Coordinator identified reliability risks associated with the entity's Operating Plan.
Note to Auditor:	

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators .

Registered Entity Response (Required):

Question: Has the Reliability Coordinator received an Emergency notification from a Transmission Operator or Balancing Authority during the compliance monitoring period? ☐ Yes ☐ No

If Yes, provide a list of such notifications. If auditor is reasonably assure of entity's No answer, then no further audit testing of Requirement R5 is necessary.

[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
Dated and time stamped evidence of notification of an Emergency received from a Transmission Operator or Balancing Authority and dated and time stamped evidence of the entity's notification of other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R5

This section to be completed by the Compliance Enforcement Authority

	(R5) Through the review of submitted evidence, verify that the entity notified other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators of the Emergency as required by Requirement R5.
Note to Auditor:	

Auditor Notes:

R6 Supporting Evidence and Documentation

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1.

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

Registered Entity Response (Required):
Question: Did the Reliability Coordinator receive a request from their Balancing Authority, or did the Reliability Coordinator declare an Energy Emergency Alert, as detailed in Attachment 1 during the compliance monitoring period? ☐ Yes ☐ No
If Yes, provide a list of such actual or potential Emergencies and proceed to the Evidence Requested section below. If auditor is reasonably assured of Reliability Coordinator's No answer, then no further audit testing of Requirement R6 is necessary.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
A list of all potential or actual Energy Emergencies in entity's footprint and operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that demonstrate initiation of an Energy Emergency Alert.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R6

This section to be completed by the Compliance Enforcement Authority

	(R6) For all, or a sample of, Balancing Authority potential or actual Energy Emergencies within the entity's Reliability Coordinator Area, verify the Reliability Coordinator declared an Energy Emergency Alert, as detailed in Attachment 1 of the EOP-011-1 Reliability Standard.
Note to Auditor:	

Auditor Notes:

Additional Information:

Reliability Standard

To be inserted by RSAW developer prior to posting of this RSAW associated with the enforceable date of this Reliability Standard.

Sampling Methodology

To be inserted by RSAW developer prior to posting of this RSAW associated with the enforceable date of this Reliability Standard, if applicable.

Regulatory Language

To be inserted by NERC Legal prior to posting of this RSAW associated with the enforceable date of this Reliability Standard.

Selected Glossary Terms

To be inserted by RSAW developer prior to posting of this RSAW associated with the enforceable date of this Reliability Standard, if applicable.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	07/17/2014	NERC Compliance, Standards, RSAWTF	New Document
2	09/22/2014	NERC Compliance, Standards, RSAWTF	Revisions based upon changes to standard for posting during first formal comment period and industry/Regional comments on RSAW.
3	11/03/2014	NERC Compliance, Standards	Revisions based upon changes to standard for posting during second formal comment period and industry/Regional comments on RSAW.

[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Reliability Standard Audit Worksheet[1]

EOP-011-1 – Emergency Operations

This section to be completed by the Compliance Enforcement Authority.

Audit ID:	Audit ID if available; or REG-NCRnnnnn-YYYYMMDD
Registered Entity:	Registered name of entity being audited
NCR Number:	NCRnnnnn
Compliance Enforcement Authority:	Region or NERC performing audit
Compliance Assessment Date(s)[2]:	Month DD, YYYY, to Month DD, YYYY
Compliance Monitoring Method:	[On-site Audit | Off-site Audit | Spot Check]
Names of Auditors:	Supplied by CEA

Applicability of Requirements

	BA	DP	GO	GOP	IA	LSE	PA	PSE	RC	RP	RSG	TO	TOP	TP	TSP
R1													X		
R2	X														
R3									X						
R4	X												X		
R5									X						
R6									X						

Legend:

Text with blue background:	Fixed text – do not edit
Text entry area with Green background:	Entity-supplied information
Text entry area with white background:	Auditor-supplied information

[1] NERC developed this Reliability Standard Audit Worksheet (RSAW) language in order to facilitate NERC's and the Regional Entities' assessment of a registered entity's compliance with this Reliability Standard. The NERC RSAW language is written to specific versions of each NERC Reliability Standard. Entities using this RSAW should choose the version of the RSAW applicable to the Reliability Standard being assessed. While the information included in this RSAW provides some of the methodology that NERC has elected to use to assess compliance with the requirements of the Reliability Standard, this document should not be treated as a substitute for the Reliability Standard or viewed as additional Reliability Standard requirements. In all cases, the Regional Entity should rely on the language contained in the Reliability Standard itself, and not on the language contained in this RSAW, to determine compliance with the Reliability Standard. NERC's Reliability Standards can be found on NERC's website. Additionally, NERC Reliability Standards are updated frequently, and this RSAW may not necessarily be updated with the same frequency. Therefore, it is imperative that entities treat this RSAW as a reference document only, and not as a substitute or replacement for the Reliability Standard. It is the responsibility of the registered entity to verify its compliance with the latest approved version of the Reliability Standards, by the applicable governmental authority, relevant to its registration status.

The NERC RSAW language contained within this document provides a non-exclusive list, for informational purposes only, of examples of the types of evidence a registered entity may produce or may be asked to produce to demonstrate compliance with the Reliability Standard. A registered entity's adherence to the examples contained within this RSAW does not necessarily constitute compliance with the applicable Reliability Standard, and NERC and the Regional Entity using this RSAW reserves the right to request additional evidence from the registered entity that is not included in this RSAW. Additionally, this RSAW includes excerpts from FERC Orders and other regulatory references. The FERC Order cites are provided for ease of reference only, and this document does not necessarily include all applicable Order provisions. In the event of a discrepancy between FERC Orders, and the language included in this document, FERC Orders shall prevail.

[2] Compliance Assessment Date(s): The date(s) the actual compliance assessment (on-site audit, off-site spot check, etc.) occurs.

Findings

(This section to be completed by the Compliance Enforcement Authority)

Req.	Finding	Summary and Documentation	Functions Monitored
R1			
R2			
R3			
R4			
R5			
R6			

Req.	Areas of Concern

Req.	Recommendations

Req.	Positive Observations

Subject Matter Experts

Identify the Subject Matter Expert(s) responsible for this Reliability Standard.

Registered Entity Response (Required; Insert additional rows if needed):

SME Name	Title	Organization	Requirement(s)

R1 Supporting Evidence and Documentation

R1. Each Transmission Operator shall develop, maintain, and implement ~~a~~one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable:

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to ~~the~~its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

1.2.6. Reliability impacts of extreme weather conditions.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

Registered Entity Response (Required):
Question: Has there ever been an Emergency where ~~this~~ ~~the Transmission~~the Transmission Operator's Operating Plan(s) has been implemented to mitigate operating Emergencies ~~has been implemented~~ during the compliance monitoring period? ☐ Yes ☐ No
If Y~~y~~es, provide a list of such Emergencies.
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below. An entity may have combined plans as a Transmission Operator and Balancing Authority.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
Documented plan(s).

Evidence of activation, such as operator logs, voice recordings, or other communications, for times when an Emergency has occurred.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.					
File Name	**Document Title**	**Revision or Version**	**Document Date**	**Relevant Page(s) or Section(s)**	**Description of Applicability of Document**

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R1

This section to be completed by the Compliance Enforcement Authority

	(R1) Confirm the plan(s) is dated and reviewed by ~~the~~ its Reliability Coordinator.
	(R1) Confirm the plan(s) was developed in accordance with Requirement R1 and includes processes for the following as applicable:
	(Part 1.1) Roles and responsibilities for activating the Operating Plan(s);
	(Part 1.2.1) Notification of its~~to the~~ Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;
	(Part 1.2.2) Cancellation or recall of Transmission and generation outages;
	(Part 1.2.3) Transmission system reconfiguration;
	(Part 1.2.4) Redispatch of generation;
	(Part 1.2.5) Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency;
	(Part 1.2.6) Reliability impacts of extreme weather conditions.
	(R1) Verify implementation of plan(s). (see note below)
Note to Auditor: Auditors can gain reasonable assurance the plan(s) was implemented by determining if specific actions prescribed by the plan(s) have taken place. For example, if the plan(s) calls for certain ~~procedures~~ processes to occur, then auditors could ask for evidence demonstrating the ~~procedure~~ process has been implemented. As auditors should obtain reasonable, not absolute, assurance the plan(s) was implemented, testing implementation on a sample basis may be appropriate.	

Auditor Notes:

R2 Supporting Evidence and Documentation

R2. Each Balancing Authority shall develop, maintain, and implement ~~a~~one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable:

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to ~~the~~its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

2.2.9. Reliability impacts of extreme weather conditions.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

Registered Entity Response (Required):

Question: Has there ever been an Emergency where ~~this~~ the Balancing Authority's Operating Plan(s) has been implemented to mitigate Capacity Emergencies and Energy Emergencies ~~has been implemented~~ during the compliance monitoring period? ☐ Yes ☐ No

If Y~~y~~es, provide a list of such Emergencies.

[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below. An entity may have combined plans as a Transmission Operator and Balancing Authority.]

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
Documented plan(s).
Evidence of activation, such as operator logs, voice recordings, or other communications, for times when an Emergency has occurred.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R2

This section to be completed by the Compliance Enforcement Authority

	(R2) Confirm the plan(s) is dated and reviewed by ~~the~~ its Reliability Coordinator.
	(R2) Confirm the plan(s) was developed in accordance with Requirement R2 and includes processes for the following as applicable:
	(Part 2.1.) Roles and responsibilities for activating the Operating Plan(s);
	(Part 2.2) Processes to prepare for and mitigate Emergencies including:
	(Part 2.2.1) Notification ~~to the~~of its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;
	(Part 2.2.2) Requesting an Energy Emergency Alert, per Attachment 1;
	(Part 2.2.3) Managing generating resources in its Balancing Authority Area to address:
	(Part 2.2.3.1) capability and availability;
	(Part 2.2.3.2) fuel supply and inventory concerns;
	(Part 2.2.3.3) fuel switching capabilities; and
	(Part 2.2.3.4) environmental constraints.

	(Part 2.2.4) Public appeals for voluntary Load reductions;
	(Part 2.2.5) Requests to government agencies to implement their programs to achieve necessary energy reductions;
	(Part 2.2.6) Reduction of internal utility energy use;
	(Part 2.2.7) Use of Interruptible Load, curtailable Load and demand response;
	(Part 2.2.8) Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and
	(Part 2.2.9) Reliability impacts of extreme weather conditions.
	(R2) Verify implementation of plan(s). (see note below)

Note to Auditor:

Auditors can gain reasonable assurance the plan(s) was implemented by determining if specific actions prescribed by the plan(s) have taken place. For example, if the plan(s) calls for certain ~~procedures~~ processes to occur, then auditors could ask for evidence demonstrating the ~~procedure~~ process has been implemented. As auditors should obtain reasonable, not absolute, assurance the plan(s) was implemented, testing implementation on a sample basis may be appropriate.

Auditor Notes:

R3 Supporting Evidence and Documentation

R3. The Reliability Coordinator~~, within 30 calendar days of receipt,~~ shall review ~~each~~the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans.

3.1. Within 30 calendar days of receipt, ~~T~~the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

M3. The Reliability Coordinator will have documentation, such as dated e-mails or other correspondences that it reviewed Transmission Operator and Balancing Authority Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.

Registered Entity Response (Required):

Compliance Narrative:

Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
The Reliability Coordinator will have documentation, such as dated e-mails or other correspondence~~s~~ that it reviewed Transmission Operator and Balancing Authority Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R3

This section to be completed by the Compliance Enforcement Authority

	(R3) Through the review of submitted evidence and interviews with entity representatives, confirm that the Reliability Coordinator reviews plans within 30-~~-~~calendar days.
Note to Auditor:	

Auditor Notes:

R4 Supporting Evidence and Documentation

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator.

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

Registered Entity Response (Required):
Question: Did entity's Reliability Coordinator identify any reliability risks associated with entity's O~~o~~perating P~~p~~~~l~~lan(s) during the compliance monitoring period?
☐ Yes ☐ No
If Y~~y~~es, provide a list of notifications. If auditor is reasonably assured of entity's N~~n~~o answer, then no further audit testing of Requirement R4 is necessary. ~~then Requirement R4 is not applicable.~~
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
Dated correspondence~~s~~ between the entity and Reliability Coordinator regarding revisions to the entity's O~~o~~perating P~~p~~lan(s) based on reliability risks identified by the Reliability Coordinator.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R4

This section to be completed by the Compliance Enforcement Authority

	(R4) Review evidence and verify the entity resubmitted its ~~O~~Ooperating ~~P~~Pplan to its Reliability Coordinator within the time period specified by the Reliability Coordinator in instances where the Reliability Coordinator identified reliability risks associated with the entity's ~~O~~Ooperating ~~P~~Pplan.
Note to Auditor:	

Auditor Notes:

R5 Supporting Evidence and Documentation

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators .

Registered Entity Response (Required):
Question: Has the Reliability Coordinator received an Emergency notification from a Transmission Operator or Balancing Authority during the compliance monitoring period? ☐ Yes ☐ No
If Y~~y~~es, provide a list of such notifications. If auditor is reasonably assure of entity's No answer, then no further audit testing of Requirement R5 is necessary. ~~If no, the Requirement R5 is not applicable.~~
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
Dated and time stamped evidence of notification of an Emergency received from a Transmission Operator or Balancing Authority and dated and time stamped evidence of the entity's notification of other ~~impacted~~ Balancing Authorit~~y~~ies and~~,~~ Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators ~~in its Reliability Coordinator Area~~.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R5

This section to be completed by the Compliance Enforcement Authority

	(R5) Through the review of submitted evidence, verify that the entity notified other ~~impacted~~ Balancing Authorities~~,~~ and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators of the Emergency as required by Requirement R5.
Note to Auditor:	

Auditor Notes:

R6 Supporting Evidence and Documentation

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1.

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

Registered Entity Response (Required):
Question: ~~Has a Balancing Authority experienced a potential or actual Energy Emergency in the Reliability Coordinatorentity's Area~~Did the Reliability Coordinator receive a request from their Balancing Authority, or did the Reliability Coordinator declare an Energy Emergency Alert, as detailed in Attachment 1- during the compliance monitoring period? ☐ Yes ☐ No
If Y~~y~~es, provide a list of such actual or potential Emergencies and proceed to the Evidence Requested section below. If auditor is reasonably assured of ~~entity~~Reliability Coordinator's No answer, then no further audit testing of Requirement R6 is necessary. ~~If no, the Requirement R5 is not applicable.~~
[Note: A separate spreadsheet or other document may be used. If so, provide the document reference below.]

Registered Entity Response (Required):
Compliance Narrative:
Provide a brief explanation, in your own words, of how you comply with this Requirement. References to supplied evidence, including links to the appropriate page, are recommended.

Evidence Requested:[i]

Provide the following evidence, or other evidence to demonstrate compliance.
A list of all potential or actual Energy Emergencies in ~~entity's Reliability Coordinator's~~entity's footprint and operator logs, voice recordings or transcripts of voice recordings, electronic communications or equivalent evidence that demonstrate initiation of an Energy Emergency Alert.

Registered Entity Evidence (Required):

The following information is requested for each document submitted as evidence. Also, evidence submitted should be highlighted and bookmarked, as appropriate, to identify the exact location where evidence of compliance may be found.

File Name	Document Title	Revision or Version	Document Date	Relevant Page(s) or Section(s)	Description of Applicability of Document

Audit Team Evidence Reviewed (This section to be completed by the Compliance Enforcement Authority):

Compliance Assessment Approach Specific to EOP-011-1, R6

This section to be completed by the Compliance Enforcement Authority

	(R6) For all, or a sample of, Balancing Authority potential or actual Energy Emergencies within the entity's Reliability Coordinator Area, verify the ~~entity~~ Reliability Coordinator declared an Energy Emergency Alert, as detailed in Attachment 1 of the EOP-011-1 Reliability Standard.
Note to Auditor:	

Auditor Notes:

Additional Information:

Reliability Standard
To be inserted by RSAW developer prior to posting of this RSAW associated with the enforceable date of this Reliability Standard.

Sampling Methodology
To be inserted by RSAW developer prior to posting of this RSAW associated with the enforceable date of this Reliability Standard, if applicable.

Regulatory Language
To be inserted by NERC Legal prior to posting of this RSAW associated with the enforceable date of this Reliability Standard.

Selected Glossary Terms
To be inserted by RSAW developer prior to posting of this RSAW associated with the enforceable date of this Reliability Standard, if applicable.

Revision History for RSAW

Version	Date	Reviewers	Revision Description
1	07/17/2014	NERC Compliance, Standards, RSAWTF	New Document
2	09/22/2014	NERC Compliance, Standards, RSAWTF	Revisions based upon changes to standard for posting during first~~second~~ formal comment period and industry/Regional comments on RSAW.
3	11~~0~~/03~~30~~/2014	NERC Compliance, Standards	Revisions based upon changes to standard for posting during second formal comment period and industry/Regional comments on RSAW.

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[i] Items in the Evidence Requested section are suggested evidence that may, but will not necessarily, demonstrate compliance. These items are not mandatory and other forms and types of evidence may be submitted at the entity's discretion.

Standards Announcement

Project 2009-03 Emergency Operations
EOP-011-1

Formal Comment Period Now Open through October 20, 2014

Now Available

A 45-day formal comment period for **EOP-011-1 – Emergency Operations** is open through **8 p.m. Eastern on Monday, October 20, 2014.**

Instructions for Commenting
Please use the electronic form to submit comments on the standards. If you experience any difficulties in using the electronic form, please contact Arielle Cunningham. An off-line, unofficial copy of the comment form is posted on the project page.

Next Steps
An additional ballot period for the standards and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 11-20, 2014.**

Note: If a member cast a vote in the initial ballot, that vote **will not** carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballots. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please case an abstention.

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Laura Anderson,
Standards Developer, or at 404-446-9671.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2009-03 Emergency Operations
EOP-011-1

Formal Comment Period Now Open through October 20, 2014

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Next Steps
An additional ballot period for the standards and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels will be conducted **October 11-20, 2014.**

Note: If a member cast a vote in the initial ballot, that vote **will not** carry over to the additional ballot. It is the responsibility of the registered voter in the ballot pool to cast a vote again in the additional ballots. To ensure a quorum is reached, if you do not want to vote affirmative or negative, please case an abstention.

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RELIABILITY CORPORATION

Standards Announcement

Project 2009-03 Emergency Operations
EOP-011-1

Additional Ballot and Non-Binding Poll Results

Now Available

An additional ballot for **EOP-011-1 – Emergency Operations** and non-binding poll of the associated Violation Risk Factors and Violation Severity Levels concluded at **8 p.m. Eastern on Monday, October 20, 2014.**

The standard achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

EOP-011-1	Non-Binding Poll
Quorum/Approval	Quorum /Approval
80.93% / 70.41%	80.12% / 70.23%

Background information for this project can be found on the project page.

Next Steps

The drafting team will consider all comments received during the formal comment period and, if needed, make revisions to the standard and post it for an additional ballot. If the comments do not show the need for significant revisions, the standard will proceed to a final ballot.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Laura Anderson.

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Ballot Results	
Ballot Name:	Project 2009-03 Emergency Operations EOP-011-1
Ballot Period:	10/10/2014 - 10/20/2014
Ballot Type:	Successive
Total # Votes:	297
Total Ballot Pool:	367
Quorum:	**80.93 % The Quorum has been reached**
Weighted Segment Vote:	70.41 %
Ballot Results:	**The Ballot has Closed**

Summary of Ballot Results

			Affirmative		Negative				
Segment	Ballot Pool	Segment Weight	# Votes	Fraction	# Votes	Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	100	1	43	0.652	23	0.348	0	9	25
2 - Segment 2	9	0.7	4	0.4	3	0.3	0	1	1
3 - Segment 3	84	1	41	0.631	24	0.369	0	6	13
4 - Segment 4	28	1	15	0.833	3	0.167	1	3	6
5 - Segment 5	78	1	37	0.638	21	0.362	0	6	14
6 - Segment 6	52	1	27	0.675	13	0.325	0	4	8
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.4	4	0.4	0	0	0	0	1
9 - Segment 9	2	0.2	2	0.2	0	0	0	0	0

10 - Segment 10	7	0.6	4	0.4	2	0.2	0	0	1
Totals	**367**	**7**	**178**	**4.929**	**89**	**2.071**	**1**	**29**	**70**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (Tom Foltz - AEP)
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Abstain	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Corporation	John Lindsey		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (FE supports RSC Comments)
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Affirmative	

1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Negative	SUPPORTS THIRD PARTY COMMENTS - (SUPPORTS THIRD PARTY COMMENTS - (NYISO/ISO/RTO Council Standards Review Committee (SRC)))
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple		
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien on behalf of David Austin - NIPSCO)
1	Ohio Valley Electric Corp.	Scott R Cunningham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas E. Foltz, American Electric Power)
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Peak Reliability	Jared Shakespeare	Negative	COMMENT RECEIVED
1	Platte River Power Authority	John C. Collins		
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO IRO Council Standards Review Committee (SRC) and PJM Interconnection LLC)

1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL Corporation NERC Registered Affiliates.)
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - I adopt the comments of the ISO/RTO Council's Standards Review Committee
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka		
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southern Indiana Gas and Electric Co.	Lynnae Wilson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum		
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wind Energy Transmission Texas, LLC	Julius Horvath	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS - (IRC/SRC and NPCC/RSC)

2	PJM Interconnection, L.L.C.	stephanie monzon		
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS - (Thomas Foltz - American Electric Power)
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO IRO Council Standards Review Committee (SRC) and PJM Interconnection LLC)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Homestead	Orestes J Garcia	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	City of Vineland	Kathy Caignon		
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO IRO Council Standards Review Committee (SRC) and PJM Interconnection LLC)
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Negative	COMMENT RECEIVED
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - RSC Comments
3	Florida Keys Electric Cooperative	Tom B Anthony		
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre		

3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover		
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (associated electric cooperative inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments.)
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Orlando Utilities Commission	Ballard K Mutters		
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO IRO Council Standards Review Committee (SRC) and PJM Interconnection LLC)
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO Council's

				Standards Review Committee)
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS - (Matthew Beilfuss)
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble		
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Negative	COMMENT RECEIVED
4	Flathead Electric Cooperative	Russ Schneider	Negative	NO COMMENT RECEIVED
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews		
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Oklahoma Municipal Power Authority	Ashley Stringer	Abstain	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	

4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Matt Beilfuss Wisconsin Electric)
5	Amerenue	Sam Dwyer		
5	American Electric Power	Thomas Foltz	Negative	COMMENT RECEIVED
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	Avista Corp.	Steve Wenke		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City and County of San Francisco	Daniel Mason		
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Negative	SUPPORTS THIRD PARTY COMMENTS - (DTE Electric is supplying comments)
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Abstain	
5	First Wind	John Robertson	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (RSC Comments)
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Negative	COMMENT RECEIVED - (Martyn Turner, Lower Colorado River Authority)

5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP RTO)
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support Joe O'Brien's comments on behalf of David Austin)
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO Council SRC)
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Southern Indiana Gas and Electric Co.	Rob Collins	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Negative	COMMENT RECEIVED

5	U.S. Army Corps of Engineers	Melissa Kurtz		
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP)
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS - (Matthew Beilfuss)
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox		
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy supports RSC comments)
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Negative	COMMENT RECEIVED - (CenterPoint Energy)
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)

6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO Council's Standards Review Committee)
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Negative	COMMENT RECEIVED
6	Westar Energy	Grant L Wilkerson	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP' Comments)
6	Western Area Power Administration - UGP Marketing	Mark Messerli		
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Brickfield, Burchette, Ritts & Stone, P.C.	Thomas W Siegrist	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Affirmative	
8	Foundation for Resilient Societies	William R Harris		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED

Non-Binding Poll Results

Project 2009-03 Emergency Operations EOP-011-1

Non-Binding Poll Results	
Non-Binding Poll Name:	Project 2009-03 Emergency Operations EOP-011-1
Poll Period:	10/10/2014 - 10/20/2014
Total # Opinions:	253
Total Ballot Pool:	327
Summaray Results:	80.12% of those who registered to participate provided an opinion or an abstention; 70.23% of those who provided an opinion indicated support for the VRFs and VSLs.

Individual Ballot Pool Results

Segment	Organization	Member	Opinions	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Abstain	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater		
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Abstain	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	

1	Cleco Corporation	John Lindsey		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Abstain	
1	Duke Energy Carolina	Doug E Hils	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS - (FE supports RSC Comments)
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch		
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	SUPPORTS THIRD PARTY COMMENTS - (Hydro-Quebec TransEnergie)
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski		
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	COMMENT RECEIVED
1	Lakeland Electric	Larry E Watt		
1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Abstain	
1	Los Angeles Department of Water & Power	faranak sarbaz	Abstain	
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	

1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	Nebraska Public Power District	Jamison Cawley		
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
1	Northeast Utilities	William Temple		
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	SUPPORTS THIRD PARTY COMMENTS - (Joe O'Brien on behalf of David Austin - NIPSCO)
1	Ohio Valley Electric Corp.	Scott R Cunningham	Abstain	
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Peak Reliability	Jared Shakespeare	Negative	COMMENT RECEIVED
1	Platte River Power Authority	John C. Collins		
1	Portland General Electric Co.	John T Walker	Affirmative	
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS - (Refer to comments submitted on behalf of PPL Corporation NERC Registered Affiliates.)
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Abstain	
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	

1	Salt River Project	Robert Kondziolka		
1	SaskPower	Wayne Guttormson	Abstain	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	
1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
1	Southern Illinois Power Coop.	William Hutchison		
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Abstain	
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Negative	COMMENT RECEIVED
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum		
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wind Energy Transmission Texas, LLC	Julius Horvath	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper		
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Negative	SUPPORTS THIRD PARTY COMMENTS - (ISO/RTO SRC)
2	New York Independent System Operator	Gregory Campoli	Abstain	
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Abstain	
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY

NERC

				COMMENTS - (Southern Company)
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Avista Corp.	Scott J Kinney		
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Homestead	Orestes J Garcia	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	Cleco Corporation	Michelle A Corley		
3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Dominion Resources, Inc.	Connie B Lowe	Abstain	
3	DTE Electric	Kent Kujala	Negative	COMMENT RECEIVED
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - RSC Comments
3	Florida Keys Electric Cooperative	Tom B Anthony	Affirmative	
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough		
3	Great River Energy	Brian Glover		
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker		

3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS - (associated electric cooperative inc.)
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	COMMENT RECEIVED
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil		
3	Louisville Gas and Electric Co.	Charles A. Freibert		
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP comments)
3	New York Power Authority	David R Rivera	Negative	SUPPORTS THIRD PARTY COMMENTS - (NPCC Comments)
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
3	Orlando Utilities Commission	Ballard K Mutters		
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Abstain	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Abstain	

3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT RECEIVED
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
3	Santee Cooper	James M Poston	Abstain	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Negative	COMMENT RECEIVED
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Group)
3	Xcel Energy, Inc.	Michael Ibold	Abstain	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble		
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Negative	COMMENT RECEIVED
4	Flathead Electric Cooperative	Russ Schneider	Negative	COMMENT RECEIVED
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews		
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Abstain	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Abstain	
4	Ohio Edison Company	Douglas Hohlbaugh		

4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace		
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS - (Matt Beilfuss Wisconsin Electric)
5	Amerenue	Sam Dwyer		
5	American Electric Power	Thomas Foltz	Abstain	
5	Arizona Public Service Co.	Scott Takinen	Affirmative	
5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
5	Avista Corp.	Steve Wenke		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Abstain	
5	Boise-Kuna Irrigation District/dba Lucky peak power plant project	Mike D Kukla	Affirmative	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose		
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl		
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	DTE Electric	Mark Stefaniak	Negative	SUPPORTS THIRD PARTY COMMENTS - (DTE Electric is supplying comments)
5	Duke Energy	Dale Q Goodwine	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)

5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	First Wind	John Robertson	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS - (RSC Comments)
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Independence Power & Light Dept.	James Nail	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southwest Power Pool)
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	COMMENT RECEIVED
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Abstain	
5	Lower Colorado River Authority	Dixie Wells	Negative	SUPPORTS THIRD PARTY COMMENTS - (Martyn Turner, Lower Colorado River Authority)
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Abstain	
5	Nevada Power Co.	Richard Salgo	Abstain	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	SUPPORTS THIRD PARTY COMMENTS - (I support Joe O'Brien's comments on behalf of

				David Austin.)
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS - (SPP Standards Review Group)
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
5	PPL Generation LLC	Annette M Bannon	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
5	PSEG Fossil LLC	Tim Kucey	Abstain	
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	SUPPORTS THIRD PARTY COMMENTS - (Denise Lietz)
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	TVA Power System Operations (PSO)	Brandy B Spraker	Abstain	
5	U.S. Army Corps of Engineers	Melissa Kurtz		

5	USDI Bureau of Reclamation	Erika Doot		
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox		
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS - (AECI)
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS - (Duke Energy)
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS - (FirstEnergy supports RSC comments)
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy		
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Abstain	
6	Lower Colorado River Authority	Michael Shaw	Negative	SUPPORTS THIRD PARTY COMMENTS - (CenterPoint Energy)
6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS - (ACES)
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY

				COMMENTS - (SPP Standards Review Group)
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Abstain	
6	Platte River Power Authority	Carol Ballantine		
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	SUPPORTS THIRD PARTY COMMENTS - (PPL NERC Registered Affiliates)
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Abstain	
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS - (Salt River Project)
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS - (Southern Company)
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II		
6	Tennessee Valley Authority	Marjorie S Parsons	Abstain	
7	Brickfield, Burchette, Ritts & Stone, P.C.	Thomas W Siegrist	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Affirmative	
8	Foundation for Resilient Societies	William R Harris		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson		
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	

10	ReliabilityFirst	Anthony E Jablonski	Affirmative	
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Affirmative	

Individual or group. (36 Responses)
Name (19 Responses)
Organization (19 Responses)
Group Name (17 Responses)
Lead Contact (17 Responses)
Question 1 (32 Responses)
Question 1 Comments (36 Responses)
Question 2 (28 Responses)
Question 2 Comments (36 Responses)
Question 3 (24 Responses)
Question 3 Comments (36 Responses)
Question 4 (28 Responses)
Question 4 Comments (36 Responses)

Group
Arizona Public Service Company
Janet Smith
Yes
No
We appreciate that the SDT addressed our comments regarding the need for definitive triggers between the EEA levels. However, with the inclusion of the final bullet of the circumstances section on EEA 2, AZPS believes that as written, the Circumstances together, where an entity is energy deficient and still maintaining their reserves at the same time, would be inappropriately burdening the interconnection. Is this the intent of the change?, If not, additional clarification around the Circumstances is requested.
Yes
No
Group
Northeast Power Coordinating Council
Guy Zito
Yes
No
In EEA 2, a bullet was added addressing the ability of the BA to maintain “minimum Contingency Reserve requirements”. This could be interpreted in two ways because of the use of the word “minimum”. It should be revised to avoid any misinterpretation. The first interpretation is that the BA would declare an EEA level 2 event though the contingency reserve requirement, equal to the BA’s Most Severe Single Contingency as defined in BAL-002-1, Part 3.1, is fully met. If this is the SDT’s intent, then suggest the following language: “An energy deficient Balancing Authority is still able to maintain Contingency Reserve requirement.” The second interpretation is that in EEA level 2, depletion of Contingency Reserve is allowed, however some minimum level(s) can still be maintained. These minimum levels are defined by local procedures and may be different from one BA to the other, based on local constraints. If this is the SDT’s intent, we then suggest the following language: “An energy deficient Balancing Authority is still able to maintain a minimum level of Contingency Reserve while Contingency Reserve may be depleted.” For example, an entity has a Contingency Reserve requirement equal to its MSSC, which is normally 1000 MW. However, there is a minimum level of 250 MW that could be maintained in all cases in order to provide minimum levels

of regulation and frequency responsive reserve. In this case, the second interpretation is the right one.
Yes
No
Individual
Leonard Kula
Independent Electricity System Operator
No
We agree with most of the changes, but have a difficulty understanding Part 3.1.2., which stipulates that: 3.1.2. Review each submitted Operating Plan for coordination to avoid risk to Wide Area reliability; and We are not clear on what it means by “Review each submitted Operating Plan for coordination”. Does it mean the RC, when reviewing the Operating Plan, needs to look for elements or confirmation of coordination between the submitting entity and other BAs and TOPs in the RC area? Or is it that the review needs to yield (and therefore the RC shall ask for or direct) coordination among the submitting entity and other BAs and TOPs in the RC area? We believe some wording change is needed to clarify the intent of this Part 3.1.2.
Yes
We agree with all the changes. Just a typo: the word “it” before “will immediately take…” should be removed from Section 3.3.1.
No
We agree with most of the assigned VRFs and VSLs, but have a concern over the lack of clear demarcation between the HIGH and SEVERE VSLs for R5. In brief, a HIGH VSL is assigned when the RC notifies others but not within the 30 minute target; whereas the RC is assigned a SEVERE VSL if it failed to notify others. It is unclear as to what time period an RC is assessed “failed to notify”. Is it 1 hour, 2 hours or 24 hours after the declaration of Emergency? The longer the period, e.g., 24 hours, the more meaningless will the HIGH VSL become since an RC may notify others 4 or 5 hours after the declaration but by that time, the Emergency may have been resolved or worsened to the point whe some cascading has occurred. We therefore suggest the SDT consider making the VSLs for R5 a fully staggered one: with a LOWER, MEDIUM, HIGH and SEVERE starting with, for example, the LOWER VSL being up to 5 minutes late in notifying others, MEDIUM VSL being up to 10 minutes late, HIGH being up to 15 minutes late and SEVERE being more than 15 minutes late (or never). The SDT may want to apply other time frames as it sees appropriate.
Individual
Brett Holland
Kansas City Power and Light
No
R1/R2 - While we have seen the ‘develop, maintain and implement’ language in other standards, we continue to be a bit unsure just how we are to use this terminology in practice. In some situations, implement means have a procedure available for use on the control room floor and that the operators have been trained on the procedure. In other situations, and it appears to us that EOP-011-1 is one of those situations, implement refers to activating the plan, process or procedure. We believe NERC needs to address what appears to be a lack of consistency as applied across the set of Reliability Standards. Another issue with this standard is the lack of direction for maintenance of an Operating Plan. Perhaps the SDT could provide additional clarification in the form of a Rationale Box which would be of assistance to the industry. R1.2.1 - Change ‘Notification to the Reliability Coordinator…’ to ‘Notification of its Reliability Coordinator…’. R1.2.5 - We appreciate the changes that the SDT incorporated to clarify the overlap between manual and automatic Load shedding. However, the rewrite may have swung the focus of the requirement away from manual Load shedding and onto the overlap. The focus should be on manual Load shedding. We offer the following to replace the existing sentence: ‘Operator-controlled manual Load shedding that is capable of being implemented in a timeframe adequate for mitigating the Emergency. Manual Load

shedding programs shall contain provisions for minimizing overlap with automatic Load shedding.' Rationale for Requirement R1 - In the last line of the 3rd paragraph, replace '...how you will make a notification to the...' with '...when the Transmission Operator must notify its...'. R2-Insert 'within its Balancing Authority Area' at the end of the 1st sentence of the requirement. R2.2.1- Change 'Notification to the Reliability Coordinator...' to 'Notification of its Reliability Coordinator...'. R2.2.8 - Again, we appreciate the changes that the SDT incorporated to clarify the overlap between manual and automatic Load shedding. However, the rewrite may have swung the focus of the requirement away from manual Load shedding and onto the overlap. The focus should be on manual Load shedding. We offer the following to replace the existing sentence: 'Operator-controlled manual Load shedding that is capable of being implemented in a timeframe adequate for mitigating the Emergency. Manual Load shedding programs shall contain provisions for minimizing overlap with automatic Load shedding.' Rational for Requirement R2 - Delete 'Emergency' in 'Emergency Operating Plan' in the last line of the 1st paragraph. In the 4th line of the 6th paragraph, set the phrase 'as much as possible' off with commas as was done in the Rationale for Requirement R1. R3 - Since the review of the Operating Plans does not specifically mitigate Emergencies, we recommend the following language for Requirement R3: '...shall review each Operating Plan to coordinate the planned actions to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority...'. Also, hyphenate '30-calendar days'. R3.1.1 - Add 'within its Reliability Coordinator Area' at the end of the Subpart. R3.1.2 - Modify the Subpart to the following: 'Review each submitted Operating Plan for coordination to avoid reliability risks within its Wide Area; and' R3.1.3 - Add 'of its review' at the end of the Subpart. Rationale for R3 - In the 3rd line, change 'require' to 'requires'. Capitalize 'Emergencies' in the last line. M3 - Hyphenate '30-calendar days'. M4 - Replace 'emails' in the 2nd line with 'e-mails' to make it consistent with the usage in M3. R5/M5 - Insert the phrase 'within its Reliability Coordinator Area' after 'Balancing Authority' in the 2nd line of this requirement. This makes the Reliability Coordinator only accountable for notifications received from within its own footprint. 'Neighboring' is used in conjunction with Reliability Coordinator at the end of this requirement. 'Adjacent' is used in Sections 3.2 and 0.1 of Attachment 1. Please be consistent with the usage. Additionally, the term 'impacted' has been deleted from the requirement. Rather than notifying only the impacted Balancing Authorities and Transmission Operators within its footprint, the Reliability Coordinator must now notify all Balancing Authorities and Transmission Operators within its footprint. When asked about this during the webinar, the SDT response was that it was a cleaner solution to the notification issue and that all Reliability Coordinators are notified if the RCIS is used. While both of these responses are correct. The use of impacted does not detract from the requirement at all. There's a good possibility that all Balancing Authorities may be notified through reserve sharing arrangements or during the search for available energy. As mentioned all Reliability Coordinators will be automatically notified if the RCIS is used, so nothing is lost there. However, if the Reliability Coordinator footprint is spread over a large geographical area, requiring the Reliability Coordinator to notify all Transmission Operators within its Reliability Coordinator Area may be excessive, especially considering that Transmission assistance from one Transmission Operator to another some distance away may not be feasible. We suggest retaining the term 'impacted'. Modify Measure M5 to be consistent with the suggested changes to Requirement R5. The language in Reqiurement R5 does not require a Reliablity Coordinator to notify impacted Balancing Authorities or Transmission Operators within its Reliability Coordinator Area of Emergencies occurring on the seams with other Reliability Coordinators. We recommend the following to ensure this notification occurs. 'Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area or neighboring Reliability Coordinator shall notify, within 30 minutes from the time of receiving notification, other impacted Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring (or adjacent) Reliability Coordinators.' Rationale for R6 - The SDT states that this requirement was created to address the FERC directives but isn't this requirement really a holdover from EOP-002-3.1, R8?
No
Introduction - In what appears to be the rationale for the introduction, insert the phrase 'as permitted in its transmission tariff' following 'request' in the 2nd line of the paragraph. General Responsibilities/Notification - Notification is to go out to all 'adjacent' Reliability Coordinators. As pointed out in Question 1 above, the term used in Requirement R5 is 'neighboring'. Neither term is really needed since Section 2.1 requires notification via the RCIS which will automatically notify all Reliability Coordinators. We suggest deleting the terms 'adjacent' and 'neighboring'. EEA Levels -

Throughout the remainder of Attachment 1, an extra space pops up between 'Reliability Coordinator' and 's' in Reliability Coordinators. The introduction section here refers to three EEA levels yet there are four identified. Either change this back to four or delete Alert 0. EEA 2 - In the paragraph immediately above 2.1, delete the extra 's' after Balancing Authorities. 2.3 - We suggest rewording the beginning of this sentence to 'Other Reliability Coordinators of Balancing Authorities with available resources…'. Otherwise a Reliability Coordinator is required to communicate with itself. 2.4 - Insert 'to-service' between 'return' and 'any' in the 3rd line. Rationale for EEA 2-Capitalize Contingency Reserves. EEA 3 - Under Circumstances it states that a Balancing Authority that is unable to sustain minimum Contingency Reserve requirements must be in an EEA 3. We appreciate the SDT's effort to clarify this position. Traditionally, lack of Operating Reserves has been associated with EEA 2. The SDT has chosen to split Contingency Reserves out and hold them as a qualifier for EEA 3 which has traditionally been associated with actual or immenient Load shedding. Such a move will increase the number of EEA 3s which could be taken as an indication of a degradation of reliability. What is the SDT's justification for making such a significant change? What are the drivers forcing this modification? In response to a question submitted via the Chat feature during the webinar, the SDT provided the following response: 'First, The previous language used "Operating Reserve," which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently and have a defined minimum value (MSSC or as defined by Reserve Sharing Group). Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using Contingency Reserve in the language would eliminate some of the confusion. Yes, this is a different approach but the Drafting Team believes this is a good approach and was supported by several commenters. Second, Using Contingency Reserve (which is subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that this point where a BA can no longer maintain this important Contingency Reserve margin is a most serious condition and puts the BA into a position where they are very close to shedding Load ("imminent or in progress"). The drafting team felt that this warrants categorization at the highest level of EEA. Finally, there is an issue concerning the move toward establishing an exemption from BAL-002 compliance when a BA is suffering an energy related emergency. Given the importance of Contingency Reserve margins, this exemption cannot be taken lightly. The drafting team believes that it is allowable to use the Contingency Reserve margin in an Emergency, but that should be the very last resort. For these reasons, the Drafting Team defined the condition where your Contingency Reserve resources, being for regulation or to serve your Load, at the highest level of Alert.' We certainly appreciate the response but believe the SDT needs to post this justification in a rationale box associated with the EEA 3 Level. That will help alleviate any misunderstanding which may exist. 3.2 - We suggest rewording the last three lines of this section to read '…Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur informing other Reliability Coordinators in the process and pass this information on to impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area.' 3.3/3.3.1 - We suggest the following changes in the last four lines of 3.3 and incorporate 3.3.1 into 3.3: 'Transmission Operator whose Transmission Owner's equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Operator whose Transmission Owner's equipment is at risk. Before SOLs or IROLs are revised, the energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding. We appreciate the SDT sharing its justification on including a lack of Contingency Reserves in EEA 3. However, this brings another question regarding when it is necessary to shed Load in order to maintain Contingency Reserves. Does the SDT believe it is necessary to shed Load to maintain Contingency Reserves? If so, under what conditions? In 3.3.1, a Balancing Authority is required to 'take whatever actions are necessary to mitigate any undue risk to the Interconnection'. This may include shedding Load. How does one determine the level of risk to the Interconnection which would drive a Balancing Authority to shed Load? 3.4 - Either delete the 'the' in front of 'Systems' in the 2nd line or change 'Systems' to 'System'. 3.4.1 - We suggest the following changes: 'Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the other Reliability Coordinators (via the RCIS) and the impacted Balancing

Authorities and Transmission Operators within its Reliability Coordinator Area that their Systems can be returned to normal limits.’
No
R1 - Change the Moderate VSL to state ‘…to mitigate operating Emergencies in its Transmission Operator Area…’ to be consistent with the requirement and the other VSLs for this requirement. Change ‘…the Reliability Coordinator.’ in the High VSL to ‘…its Reliability Coordinator.’ R2 - Add the phrase ‘within its Balancing Authority Area’ following the usage of ‘Emergencies’ in the Moderate, High and Severe VSLs for Requirement R2. R3- Insert ‘-calendar’ following ‘30’ in the High VSL. R4 - Replace ‘Transmission Operator and Balancing Authority’ with ‘responsible entity’ in the High and Severe VSLs for Requirement R4. Also, replace ‘the’ with ‘its’ when referring to the Operating Plan or Reliability Coordinator. R5 - We suggest rewording the High and Severe VSLs to read: High – The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority within it Reliability Coordinator Area, did notify impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area and other Reliability Coordinators but did not notify them within 30 minutes from the time of receiving notification. Severe – The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area, failed to notify impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area and other Reliability Coordinators.
Yes
Regarding the change of ‘energy obligation’ to ‘Load obligation’ in the definition of Energy Emergency, does the SDT believe that Load obligation includes Contingency Reserves? According to the definition of Load in the NERC Glossary, it shouldn’t. If it doesn’t, then the shift in philosophy to shedding Load to maintain Contingency Reserves needs to be reflected in the definition of Energy Emergency. We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well. The Technical Justification document has not been updated to match the currently posted draft standard.
Group
Dominion
Connie Lowe
Yes
No
Suggest revising Notification so that it is consistent with the standard. The standard uses ‘neighboring RCs’ whereas the attachment uses “adjacent RCs”. Under EEA, at 2.4 – Dominion believes this occurs only where a SOL or IROL is restricting the deficient Balancing Authority’s ability to import energy necessary to mitigate its Capacity Emergencies and Energy Emergencies. If so, suggest SDT consider explicitly stating this.
No
R5 High/Severe VSL have ‘notify impacted RCs’, the word impacted needs to be removed as it was removed in R5 and the VLS needs to be updated to match R5.
Yes
Compliance section C, Compliance Monitoring and Assessment Processes,1.3; in other Standards Under Development (IRO-002-4 and others in Project 2014-03) Dominion has noticed these items under this section have been removed and the below statement has been added to this section “As defined in the NERC Rules of Procedure, “Compliance Monitoring and Assessment Processes” refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.” If this is the direction NERC is headed, then EOP-011-1 needs to have Section 1.3 updated with the above statement for consistency.
Group
Seattle City Light
Paul Haase

Yes
Seattle City Light supports the proposed draft but asks for an explicit statement in the Standard that an entity registered as both a TOP and a BA is not required to maintain two separate Operating Plans to demonstrate compliance with R1 (TOP plan) and R2 (BA plan), and that a single plan can be compliant so long as it address the required plan elements for both functions.
Group
MRO NERC Standards Review Forum
Joe DePoorter
Yes
Thought the NSRF agrees with the re-write of EOP-011-1, please note the following discrempancy. Within R5, the word “impaced” has been removed but remains in the High and Severe VSL, and in Attachment 1, section 2.2, 3.2, 3.4.1 and 0.1. The NSRF recommends that “impacted” be re-inserted into R5 to provide clarity and inorder to be aligned with the remaining parts of the proposed Standard.
Yes
Please see question 1.
Yes
Please see question 1.
No
Individual
Thomas Foltz
American Electric Power
No
R1.2.2 and R1.2.4 specifies generation actions to be taken the Transmission Operator. These requirements hold the TOP responsible for “cancellation or recall of Transmission and generation outages” and the “Redispatch of generation request”. AEP does not believe it is within the TOP’s jurisdiction to perform such actions within their Transmission Operator Plan. Rather, AEP believes it would be the BA’s responsibility to recall generation outages or redispatch generation. AEP recommends that R.1.2.2 be changed so the BA is solely responsible for such actions, perhaps by breaking out the generation actions from R1 and making them separate from the transmission actions (possibly by adding them to the R2 requirements where the BA is responsible). In regard to R1.2.2 and R1.2.4, AEP believes the BA needs to be responsible for generation outages and the redispatch of generation. For the TOP, existing TLR or market based congestion management processes would re-dispatch generation. In an Emergency event where a generator would need redispatced for a local transmission problem, the TOP may need to contact the Reliability Coordinator. R1.2.5 could have a large impact on Transmission Operators’ installed base of manual load shedding / automatic Load shedding systems. AEP recommends the SDT take a poll on the impact using the Transmission Forum. R4 mentions a time period specified by its Reliability Coordinator. AEP believes this should incorporate a working dialog between the Reliability Coordinator and the Transmission Operator and Balancing Authority. As such AEP believes a *mutually agreed time period* would be more appropriate. Such language is used in the EOP 005-2 standard.
No
Individual
Denise M Lietz
Puget Sound Energy
No

The standard drafting team's changes resulted in a much better standard overall. However, the team did not make any change to the use of the defined term Emergency. Since this term is broad enough to include most transmission system faults, it is over inclusive and could impose a significant burden on entities as they try to demonstrate implementation of the Operating Plan. Leaving each entity to define Emergency may lead to ambiguity with enforcement later. It would be better to address the issue now - either in the standard (perhaps by expressly allowing entities to define the scope of the term) or by redefining the term to include some measure of significance.
Individual
Joe O'Brien on behalf of David Austin
NIPSCO
No
EOP-011-1 covers the long-term planning horizon and we are not quite sure why, looking at the criteria. Please clarify. How does the "Operating Plan" required under EOP-011-1 R1 for mitigating operating emergencies in the TOP area mesh with the Operating Plan required under the new TOP-002-4 R2 and the one that has to be implemented under TOP-001-3 R14? Are these Operating Plans one in the same? If so, then the requirement EOP-011-1 R1 is redundant and should be deleted as this creates confusion. The Operating Plan for EOP-011-1 R1 requires RC review, but the Operating Plan mentioned in TOP-002 does not. This is not clear and should be addressed. Thanks
Group
Tennessee Valley Authority
Dennis Chastain
No
Standard requirements should reflect Operating Plan(s), not Operating Plan. Rationale states that there can be multiple plans. Recommend uses “Plan(s)” in place of “Plan” consistently through the Standard. R2.2.3.1 and subrequirements and R2.2.9. need more clarification. Webinar discussion implied the Balancing Authority needed to have awareness of generator availability and constraints. Recommend changing R.2.2.3 to remove “Managing generating resources “ and use “Maintain awareness of generator capability and availability” and delete “to address” and the subrequirements. Recommend changing R2.2.9 by inserting “Maintain awareness of” at beginning of requirement. R3.1.1. should be clarified by inserting “within its Reliability Coordinator Area” at the end of the requirement. R3.1.3 should be clarified by inserting “submitting” after “Notify each”.
Yes
Individual
Dave Willis
Idaho Power
Yes
Yes
Yes
No

Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst votes in the Negative due to the non-enforceable language in R1 and R2 and offers the following comments for consideration: 1. Requirement R1 and R2 - ReliabilityFirst appreciates the SDT removing the “Reliability Coordinator-approved” language but still questions “Reliability Coordinator-reviewed” language. In the scenario where the Reliability Coordinator does not review the Operating Plan, is the Transmission Owner (R1) or Balancing Authority (R2) non-compliant? Furthermore, there is no corresponding requirement for the TO or BA to supply the Operating Plan to the Reliability Coordinator. To address both of ReliabilityFirst’s concerns, ReliabilityFirst suggest the following language: “Each Transmission Operator shall develop, maintain, and implement an Operating Plan to mitigate operating Emergencies in its Transmission Operator Area [and make available to the Reliability Coordinator for review]. The Operating Plan shall include the following, as applicable:” 2. Requirement R3 Part 3.1.3 - In order for consistency between R3 and R4 regarding the Reliability Coordinator specifying a time period for the TOP or BA to address identified reliability risks, ReliabilityFirst recommends modifying R3 Part 3.1.3 to state; “Notify each Balancing Authority and Transmission Operator of the results [and time period for resubmittal if reliability risks are identified].”
Group
FirstEnergycorp
Richard Hoag
No
FIRSTENERGY supports the RSC comments which are reflected below but was not provided as an option before the ballots. We agree with most of the changes, but have a difficulty understanding Part 3.1.2., which stipulates that: 3.1.2. Review each submitted Operating Plan for coordination to avoid risk to Wide Area reliability; and We are not clear on what it means by “Review each submitted Operating Plan for coordination”. Does it mean the RC, when reviewing the Operating Plan, needs to look for elements or confirmation of coordination between the submitting entity and other BAs and TOPs in the RC area? Or is it that the review needs to yield (and therefore the RC shall ask for or direct) coordination among the submitting entity and other BAs and TOPs in the RC area? We believe some wording change is needed to clarify the intent of this Part 3.1.2.
Yes
FIRSTENERGY supports the RSC comments which are reflected below but was not provided as an option before the ballots. We agree with all the changes. Just a typo: the word “it” before “will immediately take…” should be removed from Section 3.3.1.
No
FIRSTENERGY supports the RSC comments which are reflected below but was not provided as an option before the ballots. We agree with most of the assigned VRFs and VSLs, but have a concern over the lack of clear demarcation between the HIGH and SEVERE VSLs for R5. In brief, a HIGH VSL is assigned when the RC notifies others but not within the 30 minute target; whereas the RC is assigned a SEVERE VSL if it failed to notify others. It is unclear as to what time period an RC is assessed “failed to notify”. Is it 1 hour, 2 hours or 24 hours after the declaration of Emergency? The longer the period, e.g., 24 hours, the more meaningless will the HIGH VSL become since an RC may notify others 4 or 5 hours after the declaration but by that time, the Emergency may have been resolved or worsened to the point whe some cascading has occurred. We therefore suggest the SDT consider making the VSLs for R5 a fully staggered one: with a LOWER, MEDIUM, HIGH and SEVERE starting with, for example, the LOWER VSL being up to 5 minutes late in notifying others, MEDIUM VSL being up to 10 minutes late, HIGH being up to 15 minutes late and SEVERE being more than 15 minutes late (or never). The SDT may want to apply other time frames as it sees appropriate.
Yes

FIRSTENERGY supports the RSC comments which are reflected below but was not provided as an option before the ballots. The language in R1, Part 1.2 and R2, Part 2.2, which requires the Operating Plan to include, as applicable, “Processes to prepare for and mitigate Emergencies” is inconsistent with the Purpose of the Standard, that is, “…to mitigate operating Emergencies.” The words “prepare for and” should be deleted from R1, Part 1.2 and R2, Part 2.2 because that language could be interpreted to expand the scope of what the SDT intended for EOP-011-1. Specifically, when an abnormal system condition occurs, the condition may not immediately meet one or more of the three NERC “Emergency” definitions, but it could lead to an “Emergency” state. TOPs and BAs take actions to address many abnormal system conditions and, as a result, those conditions never reach an “Emergency” state.. EOP-011-1 requires the development of an Operating Plan to address operating Emergencies. However, the “prepare for” language could lead to inappropriate (and greatly expanded) identification of implementations of an Operating Plan, because it could be interpreted to include actions that are taken before an Emergency state is reached. In a follow-up response to a question about this posed at the 10/8/14 Webinar on EOP-011-1, a member of the SDT responded as follows: “It was the intention of the EOP SDT in developing EOP-011-1 for plans to be implemented under Real-time conditions of Emergency and to mitigate those Emergency conditions. From a compliance standpoint, the EOP SDT was not looking at abnormal conditions that could lead to an Emergency state.” Thus, it is clear that the words “prepare for and” should be deleted as described above because they are inconsistent with the standard’s stated purpose and the EOP SDT’s intention in developing EOP-011-1.
Individual
John Merrell
Tacoma Power
Yes
Yes
Yes
No
Group
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing
Wayne Johnson
Yes
For R5, Southern suggests revising the requirement to add clarity. Suggested wording: R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area within 30 minutes from the time of receiving the Emergency notification,. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
No
Southern understands the SDT’s approach in the revised Attachment 1, but we think there is still sufficient confusion in the industry around pre and post contingency firm load shed actions during an EEA 3. We request that the SDT provide some clarity around these actions in the Attachment 1 as suggested below but at a minimum in the consideration of comments, whitepaper, or some other form. Based on the current draft, if an entity experiences a situation where its Contingency Reserves fall below the minimum, the entity would be in an EEA3. Just because an entity’s Contingency Reserves have fallen below the minimum should not mean, however, that firm load shed is required pre-contingency in order to restore the minimum generation-side contingency reserves. Southern recommends that the “Circumstances” for EEA3 be revised to the following: The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements AND foresees

the use of firm load shed to respond post-contingency to a generation contingency event or to recover generation/load balance pre-contingency.
Yes
No
Group
PPL NERC Registered Affiliates
Brent Ingebrigtson
No
These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP. The PPL NERC Registered Affiliates support the revisions that have occurred between draft 2 and this draft 3 of Attachment A. However, additional improvements and clarification could be made. The term “extreme weather conditions” used in R1 Part 1.2.6 and R2 Part 2.2.9, is subjective. Auditors and entities may consider different types of weather “extreme.” Further description or guidance is needed to enable compliance. In addition, unlike R1 Parts 1.2.1 thru 1.2.5 and R2 Parts 2.2.1 thru 2.2.8, it is not clear how “Reliability impacts of extreme weather conditions” is a process (in part because there is no verb before reliability). If it is the SDT’s intention that Operating Plans to mitigate Emergencies include preparations for extreme weather conditions, PPL Companies recommend the following changes be made to R1 and R2: - R1 Part 1.2.6 should be moved above Part 1.2 and read, “Preparation for the reliability impacts of extreme weather conditions;” - R2 Part 2.2.9 should be moved above R2 Part 2.2 and read, “Preparation for the reliability impacts of extreme weather conditions.” Accordingly, the numbering of Parts 1.2 and 2.2 as they appear in draft 3 would become 1.3 and 2.3.
No
Attachment A, section B.2.1 – This section is preceded by the sentence, “During an EEA 2, RCs and BAs have the following responsibilities,” yet this section also includes responsibilities of market participants. What obligation do the market participants (PSEs) have to proactively look for communications from requesting BAs? Market participants (PSEs) may not have access to the RCIS website. Due to the ambiguity of the market participant responsibilities in the attachment and the fact that there are no requirements of “market participants” within the standard, PPL Companies recommend that the market participant responsibilities be removed from the attachment entirely. Attachment A, section B.2.1 - This section states that, “the requesting BA shall communicate its needs to other BAs and market participants,” but it does not describe how the BA is to make this communication. It appears this is a real time communication between the requesting BA and market participants (PSEs) but it is not clear over what medium and timeframe the communication is to occur. Attachment A, section B.2.5.1 – The mention of “all available generation units” is unnecessary as this is previously mentioned as a circumstance of an EEA1 in section B.1.
No
Group
Associated Electric Cooperative, Inc.
Phil Hart
No
AECI agrees with SPP Comments
No
AECI agrees with SPP Comments

Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
Yes
No
In EEA 2, a bullet was added addressing the ability of the BA to maintain “minimum Contingency Reserve requirements”. This could be interpreted in two ways because of the use of the word “minimum”. It should be revised to avoid any misinterpretation. The first interpretation is that the BA would declare an EEA level 2 event though the contingency reserve requirement, equal to the BA’s Most Severe Single Contingency as defined in BAL-002-1, Part 3.1, is fully met. If this is the SDT’s intent, then suggest the following language: “An energy deficient Balancing Authority is still able to maintain Contingency Reserve requirement.” The second interpretation is that in EEA level 2, depletion of Contingency Reserve is allowed, however some minimum level(s) can still be maintained. These minimum levels are defined by local procedures and may be different from one BA to the other, based on local constraints. If this is the SDT’s intent, we then suggest the following language: “An energy deficient Balancing Authority is still able to maintain a minimum level of Contingency Reserve while Contingency Reserve may be depleted.” For example, an entity has a Contingency Reserve requirement equal to its MSSC, which is normally 1000 MW. However, there is a minimum level of 250 MW that could be maintained in all cases in order to provide minimum levels of regulation and frequency responsive reserve. In this case, the second interpretation is the right one.
Yes
Yes
R1 – Paragraphs 1.2.1 and 1.2.4 are ambiguous Regarding 1.2.1, two possible interpretations a) TOP should notify RC of current and projected conditions. 1.2.1. Notification to the Reliability Coordinator of current and projected conditions, when experiencing an operating Emergency; b) However, If the purpose is for TOP to notify RC to actually include the current and projected conditions, then the following question is to include them in what? In that case, there is a part of the sentence that is missing. Regarding 1.2.4, the phrasing is ambiguous: 2 possible interpretations and rephrasings depending on if the purpose of the process is to redispatch or to request redispatch. a) 1.2 Process to prepare for and mitigate Emergencies including: 1.2.4. Redispatch of generation b) 1.2 Process to prepare for and mitigate Emergencies including: 1.2.4 Request for redispatch of generation R2- Same comments apply to 2.2.1 as those made regarding 1.2.1 R3 – Table of Compliance Elements There is no VSL if the RC does not review the Plan. We suggest that this be added to the Severe VSL . R5- A RC may have numerous BA and TOP in its RC area who are not necessarily affected by an emergency declared by one of them. We suggest the use of the same terminology as that used in the Table of Compliance section of the standard which refers to impacted entities. Therefore, R5 would read: Each RC that receives an Emergency notification from a TOP or BA shall notify, within 30 minutes from the time of receiving notification, other impacted or potentially impacted BA and TOP in its RC Area, and neighboring RCs, Same comment applies to M5. Attachment 1, section 3.3.1.: there is a typographical error. The energy deficient BA, upon notification from its RC of the situation, it will immediately take whatever actions are necessary (…)
Individual
Matthew Beilfuss
We Energies
No
R1 and R2: The use of the term [implement] in the opening sentences of R1 and R2 should be removed and replaced with an additional sentence; the BA/TOP [shall act in accordance with their plan to mitigate a Capacity Emergency or Energy Emergency.]. The word implement can be interpreted to create a pre-emergency obligation (to train or provide other evidence of awareness) relative to the developed and maintained Operating Plan. To an extent, the measures for R1 and R2 address this issue with the phrase, [for times when an Emergency has occurred]. However, replacing implement with shall act in accordance with adds clarity to the requirement. R1.2.5 and R2.2.8: The

requirements include language to [minimize] overlap of manual and automatic load shed and require that manual load shed be capable of being implemented in a [timeframe adequate for mitigating the Emergency.] This language creates requirements that are ambiguous and would be difficult to both audit and prove compliance. Additionally, the SDT's goal of keeping manual and automatic Load shed schemes as separate as possible does not fully consider the interaction between a TOP's UVLS and a BA's UFLS schemes. A BA maintaining separation between their manual load shed and UFLS, may have manual load shed plans that remove a TOP's UVLS. Additionally, the objective of a BA using manual load shed to respond to Energy Emergencies and Capacity Emergencies is to balance the BA. UFLS under non-islanded conditions has a broader purpose of maintaining the entire Interconnection. R2.2.8: This requirement combines the Balancing Authority functional model role and the implementation of operator controlled manual Load shedding, which aligns with the DP role. The requirement is written assuming a vertically integrated utility with both BA and DP roles. When considering the functional model, a BA would affect manual load shed through the use of an Operating Instruction to a DP to shed the load. A non-vertically integrated BA does not have the means to directly affect load shed without an Operating Instruction. R3. The requirement does not identify a periodicity or requirements for ongoing RC review of Operating Plans, nor does it address timing of Operating Plan submittal to the RC. As the requirement is written, the first TOP or BA to submit a plan will receive the results of the RC review within 30 days. It is not clear to whom will the RC compare initially submitted plan if all the BA's or TOPs do not submit their plans at the same time. Alternately, if all BA / TOP plans are submitted to the RC at the same time, how effective will an RC review be if they are required complete their review within 30 calendar days? EOP 005-2 contains a well thought out process for periodicity and timing of submitting plans to an RC and should be considered as a template for this requirement. R4. As written, the requirement does not establish a set timeframe for the BA/TOP to address reliability risks identified during the RC review of the Operating Plans. R5: The phrase [and neighboring Reliability Coordinators] should be replaced with [and adjacent Reliability Coordinators.] This would be consistent with the notification process in Attachment 1, which requires the RC to [also notify all adjacent Reliability Coordinators.]
Yes
Yes
No
Group
SPP Standards Review Group
Robert Rhodes
No
R1/R2 - While we have seen the 'develop, maintain and implement' language in other standards, we continue to be a bit unsure just how we are to use this terminology in practice. In some situations, implement means have a procedure available for use on the control room floor and that the operators have been trained on the procedure. In other situations, and it appears to us that EOP-011-1 is one of those situations, implement refers to activating the plan, process or procedure. We believe NERC needs to address what appears to be a lack of consistency as applied across the set of Reliability Standards. Another issue with this standard is the lack of direction for maintenance of an Operating Plan. Perhaps the SDT could provide additional clarification in the form of a Rationale Box which would be of assistance to the industry. R1.2.1 - Change 'Notification to the Reliability Coordinator…' to 'Notification of its Reliability Coordinator…'. R1.2.5 - We appreciate the changes that the SDT incorporated to clarify the overlap between manual and automatic Load shedding. However, the rewrite may have swung the focus of the requirement away from manual Load shedding and onto the overlap. The focus should be on manual Load shedding. We offer the following to replace the existing sentence: 'Operator-controlled manual Load shedding that is capable of being implemented in a timeframe adequate for mitigating the Emergency. Manual Load shedding programs shall contain provisions for minimizing overlap with automatic Load shedding.' Rationale for Requirement R1 - In the last line of the 3rd paragraph, replace '…how you will make a notification to the…' with '…when the Transmission Operator must notify its…'. R2-Insert 'within its Balancing Authority Area' at the end of the 1st sentence of the requirement. R2.2.1- Change

‘Notification to the Reliability Coordinator…’ to ‘Notification of its Reliability Coordinator…’. R2.2.8 - Again, we appreciate the changes that the SDT incorporated to clarify the overlap between manual and automatic Load shedding. However, the rewrite may have swung the focus of the requirement away from manual Load shedding and onto the overlap. The focus should be on manual Load shedding. We offer the following to replace the existing sentence: ‘Operator-controlled manual Load shedding that is capable of being implemented in a timeframe adequate for mitigating the Emergency. Manual Load shedding programs shall contain provisions for minimizing overlap with automatic Load shedding.’ Rational for Requirement R2 - Delete ‘Emergency’ in ‘Emergency Operating Plan’ in the last line of the 1st paragraph. In the 4th line of the 6th paragraph, set the phrase ‘as much as possible’ off with commas as was done in the Rationale for Requirement R1. R3 - Since the review of the Operating Plans does not specifically mitigate Emergencies, we recommend the following language for Requirement R3: ‘…shall review each Operating Plan to coordinate the planned actions to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority…’. Also, hyphenate ‘30-calendar days’. R3.1.1 - Add ‘within its Reliability Coordinator Area’ at the end of the Subpart. R3.1.2 - Modify the Subpart to the following: ‘Review each submitted Operating Plan for coordination to avoid reliability risks within its Wide Area; and’ R3.1.3 - Add ‘of its review’ at the end of the Subpart. Rationale for R3 - In the 3rd line, change ‘require’ to ‘requires’. Capitalize ‘Emergencies’ in the last line. M3 - Hyphenate ’30-calendar days’. M4 - Replace ‘emails’ in the 2nd line with ‘e-mails’ to make it consistent with the usage in M3. R5/M5 - Insert the phrase ‘within its Reliability Coordinator Area’ after ‘Balancing Authority’ in the 2nd line of this requirement. This makes the Reliability Coordinator only accountable for notifications received from within its own footprint. ‘Neighboring’ is used in conjunction with Reliability Coordinator at the end of this requirement. ‘Adjacent’ is used in Sections 3.2 and 0.1 of Attachment 1. Please be consistent with the usage. Additionally, the term ‘impacted’ has been deleted from the requirement. Rather than notifying only the impacted Balancing Authorities and Transmission Operators within its footprint, the Reliability Coordinator must now notify all Balancing Authorities and Transmission Operators within its footprint. When asked about this during the webinar, the SDT response was that it was a cleaner solution to the notification issue and that all Reliability Coordinators are notified if the RCIS is used. While both of these responses are correct. The use of impacted does not detract from the requirement at all. There’s a good possibility that all Balancing Authorities may be notified through reserve sharing arrangements or during the search for available energy. As mentioned all Reliability Coordinators will be automatically notified if the RCIS is used, so nothing is lost there. However, if the Reliability Coordinator footprint is spread over a large geographical area, requiring the Reliability Coordinator to notify all Transmission Operators within its Reliability Coordinator Area may be excessive, especially considering that Transmission assistance from one Transmission Operator to another some distance away may not be feasible. We suggest retaining the term ‘impacted’. Modify Measure M5 to be consistent with the suggested changes to Requirement R5. The language in Reqiurement R5 does not require a Reliablity Coordinator to notify impacted Balancing Authorities or Transmission Operators within its Reliability Coordinator Area of Emergencies occurring on the seams with other Reliability Coordinators. We recommend the following to ensure this notification occurs. ‘Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area or neighboring Reliability Coordinator shall notify, within 30 minutes from the time of receiving notification, other impacted Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring (or adjacent) Reliability Coordinators.’ Rationale for R6 - The SDT states that this requirement was created to address the FERC directives but isn’t this requirement really a holdover from EOP-002-3.1, R8?
No
Introduction - In what appears to be the rationale for the introduction, insert the phrase ‘as permitted in its transmission tariff’ following ‘request’ in the 2nd line of the paragraph. General Responsibilities/Notification - Notification is to go out to all ‘adjacent’ Reliability Coordinators. As pointed out in Question 1 above, the term used in Requirement R5 is ‘neighboring’. Neither term is really needed since Section 2.1 requires notification via the RCIS which will automatically notify all Reliability Coordinators. We suggest deleting the terms ‘adjacent’ and ‘neighboring’. EEA Levels - Throughout the remainder of Attachment 1, an extra space pops up between ‘Reliability Coordinator’ and ‘s’ in Reliability Coordinators. The introduction section here refers to three EEA levels yet there are four identified. Either change this back to four or delete Alert 0. EEA 2 - In the paragraph immediately above 2.1, delete the extra ‘s’ after Balancing Authorities. 2.3 - We suggest rewording

the beginning of this sentence to ‘Other Reliability Coordinators of Balancing Authorities with available resources...’. Otherwise a Reliability Coordinator is required to communicate with itself. 2.4 - Insert ‘to-service’ between ‘return’ and ‘any’ in the 3rd line. Rationale for EEA 2-Capitalize Contingency Reserves. EEA 3 - Under Circumstances it states that a Balancing Authority that is unable to sustain minimum Contingency Reserve requirements must be in an EEA 3. We appreciate the SDT’s effort to clarify this position. Traditionally, lack of Operating Reserves has been associated with EEA 2. The SDT has chosen to split Contingency Reserves out and hold them as a qualifier for EEA 3 which has traditionally been associated with actual or immenient Load shedding. Such a move will increase the number of EEA 3s which could be taken as an indication of a degradation of reliability. What is the SDT’s justification for making such a significant change? What are the drivers forcing this modification? In response to a question submitted via the Chat feature during the webinar, the SDT provided the following response: ‘First, The previous language used “Operating Reserve,” which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently and have a defined minimum value (MSSC or as defined by Reserve Sharing Group). Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using Contingency Reserve in the language would eliminate some of the confusion. Yes, this is a different approach but the Drafting Team believes this is a good approach and was supported by several commenters. Second, Using Contingency Reserve (which is subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that this point where a BA can no longer maintain this important Contingency Reserve margin is a most serious condition and puts the BA into a position where they are very close to shedding Load (“imminent or in progress”). The drafting team felt that this warrants categorization at the highest level of EEA. Finally, there is an issue concerning the move toward establishing an exemption from BAL-002 compliance when a BA is suffering an energy related emergency. Given the importance of Contingency Reserve margins, this exemption cannot be taken lightly. The drafting team believes that it is allowable to use the Contingency Reserve margin in an Emergency, but that should be the very last resort. For these reasons, the Drafting Team defined the condition where your Contingency Reserve resources, being for regulation or to serve your Load, at the highest level of Alert.’ We certainly appreciate the response but believe the SDT needs to post this justification in a rationale box associated with the EEA 3 Level. That will help alleviate any misunderstanding which may exist as well as provide a permanent record of why the change was made. 3.2 - We suggest rewording the last three lines of this section to read ‘...Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur informing other Reliability Coordinators in the process and pass this information on to impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area.’ 3.3/3.3.1 - We suggest the following changes in the last four lines of 3.3 and incorporate 3.3.1 into 3.3: ‘Transmission Operator whose Transmission Owner’s equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Operator whose Transmission Owner’s equipment is at risk. Before SOLs or IROLs are revised, the energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding. We appreciate the SDT sharing its justification on including a lack of Contingency Reserves in EEA 3. However, this brings another question regarding when it is necessary to shed Load in order to maintain Contingency Reserves. Does the SDT believe it is necessary to shed Load to maintain Contingency Reserves? If so, under what conditions? In 3.3.1, a Balancing Authority is required to ‘take whatever actions are necessary to mitigate any undue risk to the Interconnection’. This may include shedding Load. How does one determine the level of risk to the Interconnection which would drive a Balancing Authority to shed Load? 3.4 - Either delete the ‘the’ in front of ‘Systems’ in the 2nd line or change ‘Systems’ to ‘System’. 3.4.1 - We suggest the following changes: ‘Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the other Reliability Coordinators (via the RCIS) and the impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area that their Systems can be returned to normal limits.'
No

R1 - Change the Moderate VSL to state '...to mitigate operating Emergencies in its Transmission Operator Area...' to be consistent with the requirement and the other VSLs for this requirement. Change '...the Reliability Coordinator.' in the High VSL to '...its Reliability Coordinator.' R2 - Add the phrase 'within its Balancing Authority Area' following the usage of 'Emergencies' in the Moderate, High and Severe VSLs for Requirement R2. R3- Insert '-calendar' following '30' in the High VSL. R4 - Replace 'Transmission Operator and Balancing Authority' with 'responsible entity' in the High and Severe VSLs for Requirement R4. Also, replace 'the' with 'its' when referring to the Operating Plan or Reliability Coordinator. R5 - We suggest rewording the High and Severe VSLs to read: High – The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area, did notify impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area and other Reliability Coordinators but did not notify them within 30 minutes from the time of receiving notification. Severe – The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area, failed to notify impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area and other Reliability Coordinators.
Yes
Regarding the change of 'energy obligation' to 'Load obligation' in the definition of Energy Emergency, does the SDT believe that Load obligation includes Contingency Reserves? According to the definition of Load in the NERC Glossary, it shouldn't. If it doesn't, then the shift in philosophy to shedding Load to maintain Contingency Reserves needs to be reflected in the definition of Energy Emergency. We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well. The Technical Justification document has not been updated to match the currently posted draft standard.
Individual
Joshua Andersen
Salt River Project
No
SRP appreciated the efforts at revising the requirement for the Operating Plan to be approved by the Reliability Coordinator to just require reviewal of the Operating Plan. However, there is no time frame or periodicity mentioned for when the Operating Plan should be reviewed. Please address when the Operating Plan needs to be reviewed.
Yes
Yes
No
Individual
Jo-Anne Ross
Manitoba Hydro
No
Requirement R4 – the requirement that each Transmission Operator and Balancing Authority shall "address" any reliability risks... should berevised to state that each Transmission Operator and Balancing Authority shall "make a good faith attempt to address" any reliability risks identified by its Reliability Coordinator pursuant to Requirment R3. Requirment R3.1.1 requires the Reliability Coordinator to review each submitted Operating Plan on the basis of compatability and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans.. This implies that a given Transmission Operator or Balancing Authority may need to negotiate a modified approach with other Transmission Operators or Balancing Authorities . Since one party cannot compel an agreement with another party, only god faith efforts can be made to resolve an incompatibility . There is no mechanism or criteria specified in R3 for the Reliability Coordinator to pick one plan over another if two or more operating plans are inconsistent.
Yes

Yes
Yes
Requirement R2.2.7 “Use of Interruptible Load, curtailable Load and demand response.” The term curtailable Load is redundant as it is already included in the definition of” Interruptible Load in the “Glossary of Terms Used in NERC Reliability Standards” as “Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.”
Group
DTE Electric
Kathleen Black
No
Comments: The language in R3 requires the RC to review plans within 30 days but does not specify a time limit to notify the BA or TOP. R3 also does not require the RC to specify a time period to the BA or TOP to address issues but R4 requires those issues to be addressed in a specified time frame. Suggested new language for R3: R3. The Reliability Coordinator, within 30 calendar days of receipt, shall review each Operating Plan to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. 3.1. The Reliability Coordinator review shall consist of the following actions: 3.1.1. Review each submitted Operating Plan on the basis of compatibility and inter-dependency with other Balancing Authorities’ and Transmission Operators’ Operating Plans; 3.1.2. Review each submitted Operating Plan for coordination to avoid risk to Wide Area reliability; 3.1.3. Notify each Balancing Authority and Transmission Operator of the results; and 3.1.4. If risks are identified, specify a time frame for the affected Balancing Authority or Transmission Operator to address the risks and resubmit its plan. [Violation Risk Factor: High] [Time Horizon: Operations Planning]
Yes
No
Comments: For R3 High VSL, the requirement as written does not specify notification within 90 days. Our suggested revision to R3 in response to question 1 corrects this issue.
No
Due to the lack of time being defined in Requirements 3 & 4, we are voting negative for this ballot period.
Individual
Chris Scanlon
Exelon Companies
No
Requirement 1 states theTransmission Operator shall develop, maintain and implement an Operating Plan that includes: Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency. We are concerned with the use of “minimizes” and “adequate timeframe”. This is open to interpretaion by compliance audit staff.
No
The VSL for R1 does not identify any of the sub requiirments in the standard, the VSL's lack specificity.
No
Individual
Sonya Green-Sumpter
South Carolina Electric & Gas
Yes

Yes
Yes
No
Group
Duke Energy
Michael Lowman
No
(1) Duke Energy suggests the following revision to requirement 1.2.5: “1.2.5. Provisions for operator-controlled manual Load shedding that are capable of being implemented in a timeframe adequate for mitigating the Emergency; and...” We believe that it will be difficult to demonstrate compliance to an auditor that an entity has provisions in place to “minimize the overlap with automatic Load shedding” which are adequate. This phrase makes the requirement subjective, and would make measuring compliance for auditors difficult due to the varying nature with which each entity could approach meeting compliance with this requirement. (2) Could the SDT please clarify our understanding of the phrase “capable of being implemented in a timeframe adequate for mitigating the Emergency...” within requirement 1.2.5? It is our understanding that this phrase provides an entity the flexibility to identify on its own, the timeframes it deems adequate for mitigating emergencies within their Operating Plan. Is this correct? (3) Duke Energy suggests the following revision to the definition of Energy Emergency: “Energy Emergency - A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load or balancing obligations respectively.” Per the NERC Functional Model, the LSE has the obligation to serve load and the BA has the obligation to maintain balance. We believe the addition of “Load or balancing obligations respectively” more accurately distinguishes the separate responsibilities of a LSE or BA during an Energy Emergency. . (4) Duke Energy suggests the following revision to requirement 2.2.8: “2.2.8. Provisions for operator-controlled manual Load shedding that are capable of being implemented in a timeframe adequate for mitigating the Emergency; and...” We believe that it will be difficult to demonstrate compliance to an auditor that an entity has provisions in place to “minimize the overlap with automatic Load shedding” which are adequate. This phrase makes the requirement subjective, and would make measuring compliance for auditors difficult due to the varying nature with which each entity could approach meeting compliance with this requirement. (5) Duke energy suggests combining Requirements 3 and 4 as follows: “Each RC and Balancing Authorities and Transmission Operators within its RC Area shall review and revise the BA and TOP Operating Plans as necessary for coordination.” We believe the proposed R3 and R4 are too prescriptive in nature and may not address the intent of the SDT of promoting coordination of the Operating Plans among the listed functions. We feel that our suggested language captures more clearly the desired coordination as intended by the SDT. (6) Duke Energy suggests the following revision to requirement 5: “Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority, as identified in its respective Operating Plan shall notify, within 30 minutes from the time of receiving notification, affected Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and affected neighboring Reliability Coordinators.” We believe the NERC definition of Emergency is too broad within the context of this requirement. Per the NERC definition of Emergency, any tripping of generation or transmission line that “requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System” would be subject to notification. This would be extremely burdensome for the RC(s), BA(s), and TOP(s). We believe the intent is for the RC to notify affected parties during an event that would put the reliability of the BES at risk. We believe our suggested language narrows the scope to only those events that have that very impact. We also believe that this was the intent of the SDT and not to require that every action taken by a BA/TOP prompt notifications to all BA(s) and TOP(s) within its RC area as well as neighboring RC(s). (7) We ask the EOP SDT to distinguish the differences between EOP-011-1 R5 and IRO-014-3 R3. As written, we believe the 2 requirements listed are similar and would create double jeopardy.
No

(1)Duke Energy suggests the following revision to A.1. of Attachment 1: “1. Declaration by Reliability Coordinator. An Energy Emergency Alert (EEA) may be declared only by a Reliability Coordinator at 1) the Reliability Coordinator’s own discretion, or 2) upon the request of the Balancing Authority or Load Serving Entity.” We still believe that at a minimum, EOP-011 should retain the LSE's ability to request that an RC declare an EEA. Though EOP-011 and Attachment 1 may not have to be prescriptive in the activities expected of LSEs during an energy emergency, we believe that the responsibility of LSEs to procure additional resources as needed to address real-time deficiencies needs to be clearly understood and not be inadvertently moved to the Host BA by the changes proposed. In addition, LSEs who are not part of ISO/RTO markets should still have the ability to notify the RC or BA when they are experiencing an energy emergency. Finally, we believe that the RC is responsible for declaring an EEA and the associated notifications. The BA or LSE is responsible for initiating the EEA through the notification to the RC. (2)Duke Energy suggests the following revision to A.2. of Attachment 1: “Notification. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all adjacent Reliability Coordinators of system conditions.” We believe the added language provides additional clarity. (3)Duke Energy suggests removing RCIS for 2.1 and 2.2 of EEA 2, 3.4.1 of EEA 3, and 0.1 of EEA 0 to be consistent with the removal of RCIS in Section A, General Responsibilities. (4)Duke Energy believes that a white paper or guidance document is needed to clarify the necessary actions taken at each EEA level. As written, it is difficult to identify those actions and a white paper or guidance document would be beneficial. (5)There appear to be typos within the attachment and suggest replacing “Reliability Coordinator s” with “Reliability Coordinator’s “ (6) Duke Energy suggests replacing “terminates” with “downgraded” in section 3.2 of Attachment 1. We believe this change better clarifies the SDT’s intent and is also consistent with the language in 3.4.1. (7) Duke Energy suggests replacing “requirements” with “actions” in section 3.3 of Attachment 1. We believe this change better clarifies the SDT’s intent. (8)Duke energy suggests the following revision to 3.4.1 of Attachment 1: “Notification of other parties. Upon downgrading the alert by the Reliability Coordinator, the Reliability Coordinator shall notify the impacted Reliability Coordinator’s, Balancing Authorities and Transmission Operators that its Systems can be returned to its normal limits.” We believe that the notification piece by a BA has already been established as part of 3.4 and is not necessary in 3.4.1. (9)Duke Energy suggests replacing “Operating Reserves” with “Contingency Reserves” to be consistent with maintaining Contingency Reserves as outlined in Attachment 1. If the SDT believes that Operating Reserve is the appropriate term, can the SDT explain the rationale behind using Operating Reserve instead of Contingency Reserve?
Yes
No
Individual
Catherine Wesley
PJM Interconnection
PJM is signing onto the SRC's comments.
Individual
Matthew F. Goldberg
ISO New England Inc.
Yes
The language in R1, Part 1.2 and R2, Part 2.2, which requires the Operating Plan to include, as applicable, "Processes to prepare for and mitigate Emergencies" is inconsistent with the Purpose of

the Standard, that is, "...to mitigate operating Emergencies." The words "prepare for and" should be deleted from R1, Part 1.2 and R2, Part 2.2 because that language could be interpreted to expand the scope of what the SDT intended for EOP-011-1. Specifically, when an abnormal system condition occurs, the condition may not immediately meet one or more of the three NERC “Emergency” definitions, but it could lead to an “Emergency” state. TOPs and BAs take actions to address many abnormal system conditions and, as a result, those conditions never reach an “Emergency” state.. EOP-011-1 requires the development of an Operating Plan to address operating Emergencies. However, the “prepare for” language could lead to inappropriate (and greatly expanded) identification of implementations of an Operating Plan, because it could be interpreted to include actions that are taken before an Emergency state is reached. In a follow-up response to a question about this posed at the 10/8/14 Webinar on EOP-011-1, a member of the SDT responded as follows: “It was the intention of the EOP SDT in developing EOP-011-1 for plans to be implemented under Real-time conditions of Emergency and to mitigate those Emergency conditions. From a compliance standpoint, the EOP SDT was not looking at abnormal conditions that could lead to an Emergency state.” Thus, it is clear that the words “prepare for and” should be deleted as described above because they are inconsistent with the standard’s stated purpose and the EOP SDT’s intention in developing EOP-011-1.
Individual
Gregory Campoli
New York Independent System Operator
No
The NYISO proposes the following additions: Section 2.4 should include the phrase: ".. in order to mitigate the energy emergency. " Section 2.5.1 requires all generators to be on-line. The NYISO would like to clarify that this does not include quick start units (e.g., 10 minute GT resources) used to maintain contingency reserve while off-line? Section 3.3 indicates that revised SOL/IROLs would only be revised as long as the EEA 3 condition exists. The NYISO is unclear on what conditions related to an EEA 3 would require an entity to restore previous SOL/IROL's. If a new SOL/IROL was developed would that not be valid for the existing conditions?
Group
ACES Standards Collaborators
Ben Engelby
No
(1) We thank the drafting team for modifying Requirement R1 by requiring an Operating Plan rather than an Emergency Operating Plan. (2) If an entity is registered as both a BA and a TOP, would they need two operating plans to address the differences in R1 and R2? If so, we recommend revising these requirements to eliminate duplicative efforts for compliance purposes. (3) For Requirement R3, Part 3.1.3, is there a time frame in which the RC must notify each BA and TOP? Requirement R3 states that the RC must review the Operating Plan within 30 calendar days of receipt, but there is no deadline to provide notice to the submitting entity. (4) For Requirement R4, there are concerns with the timeframes to update and resubmit modified Operating Plans. The requirement should include 30 calendar days of receipt, unless the RC mandates the change to be made sooner. Without any specific timeline, this requirement is difficult to measure what a reasonable time frame would be. (5) We disagree with using the term “minimizes” in Parts 1.2.5 and 2.2.8. This implies that an optimal solution is required. While we agree it does makes sense to be thoughtful in the selection of loads for manual load shed, it simply may not be possible to avoid shedding loads that can also be shed via UFLS in many cases. For instance, there could be many critical loads (i.e. fire and police stations, army bases, hospitals) that prevent this and the system operator should not be burdened in a real-time Emergency with this “minimization” issue when they should be focused on mitigating the Emergency. Also, transmission Emergencies may require loads in a load pocket that has many UFLS relays to be shed. We suggest that Parts 1.2.5 and 2.2.8 be struck in their entirety and to cover this concept in the guidelines sections. The last paragraph in the rationale box for R1 and second to last paragraph for the rationale box for R2 both that the goal is to “minimize as much as possible.” This

is inconsistent with the language of the requirement which requirements minimization. (6) Requirement R3 is inconsistent with Requirement R2. The requirement compels the RC to review Operating Plans “to mitigate operating Emergencies.” R1 uses the term operating Emergencies. R2 does not but rather uses Capacity and Energy Emergencies. R3 should be made consistent with the language in R2.
No
(1) We question the re-evaluation and revision of SOLs and IROLs during an EEA 3. First, this step should be completed prior to entering EEA3 because load shed is already occurring or is imminent. We understand that there is a step 2.4 under EEA 2 that considers that impact of Transmission outages on IROLs and SOLs but it does not call for re-evaluation or revising of IROLs and SOLs even if Transmission Elements are returned to service. By the time the situation reaches EEA 3, load shedding is occurring. If there are activities, such as reevaluating SOLs (e.g. using a shorter duration emergency limit) to prevent load shedding, the re-evaluation should occur during should be done during EEA 2 with implementation of the new limit in EEA 3. (2) We believe section 3.3.1 and the last sentence of 3.3 should be struck as they are ambiguous and cause confusion. First, section 3.3.1 appears to limit use of revised SOLs and IROLs until after load shed occurs. The bottom line is revised IROLs and SOLs should be used to prevent load shed not mitigate it once it has occurred. The RC can revise IROLs at any and the TOP can revise SOLs at anytime as long as they are consistent with the RC’s SOLs methodology. (3) Section 3.3 is inconsistent with FAC-014 and FAC-011. FAC-014 requires the RC to establish an SOL methodology and FAC-011 requires the RC to establish IROLs and the TOP to establish SOLs consistent with the methodology. The RC does not require TOP agreement to modify IROLs as they have the authority to establish an IROL. The only real issue here is that the RC and TOP need to make sure they are not violating the TOP’s Facility Ratings established per their Facility Ratings methodology (FAC-008). FAC-011 R1.2 already requires this. We suggest simply stating that “Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and Transmission Operators consistent with the RC’s SOL Methodology and TO’s Facility Ratings Methodology.” (4) We question why a BA has to communicate its needs to other BAs in EEA2. They should only be required to notify its RC who then communicates the issue via RCIS which will notify all BAs at the same time. This avoids the compliance issue of whether the RC notification per the RCIS satisfies the BA’s obligation. (5) There are several extraneous “s” in the attachment usually after Reliability Coordinator or Balancing Authority. Look at the last sentence of EEA2 for example.
No
(1) We recommend adding a Lower VSL table for Requirement R1. There may be several factors, such as late annual reviews (one to three months late) that could result in a lower VSL. (2) For Requirement R4, we recommend adding a Lower and Moderate VSL. Failing to make updates by the RC deadline by a short time (one to thirty days) could be a Lower or Moderate VSL. (3) For Requirement R5, the Severe VSL requires notification of “impacted” RCs, BAs, and TOPs but the requirement states “adjacent” RCs, BAs, and TOPs. Which entities are required to be notified, impacted or adjacent?
Yes
(1) We question the inclusion of LSE in proposed definition of Energy Emergency. The Risk Based Registration (RBR) project is proposing to remove the LSE function. If the LSE is retired, does this proposed definition logically make sense? The definition should be revised to remove the LSE and focus the activities on the Balancing Authority. Furthermore, unless the BA is also in an EEA it is highly unlikely for an individual LSE in the Host BA to be in an EEA as this implies there is excess energy available in the Host BA. The LSE should not be an applicable entity for EOP-011-1. (2) Thank you for the opportunity to comment.
Individual
Karin Schweitzer
Texas Reliability Entity
No
In Requirement R1, use of the term “Transmission Operator Area” appears to assume that generation supply physically located within a Transmission Operator’s footprint is part of their “Transmission Operator Area.” As currently defined, “Transmission Operator Area” is the collection of Transmission assets that the Transmission Operator is responsible for operating. Using this definition

in the requirement may create a reliability gap if a TOP determines that generation facilities are not included in the Transmission Operator Area because they don't meet the definition of Transmission. For example, in the ERCOT region some TOPs have argued that certain generation units are not in their Transmission Operator Area and therefore the TOP is not required to monitor those facilities. A TOP’s Operating Plan for mitigating operating Emergencies should include all applicable generation supply (per the FERC-approved definition of Emergency) to eliminate any potential reliability gaps. Accordingly, Texas RE offers several options to resolve this reliability gap concern: 1) Revise the current approved definition of “Transmission Operator Area” to add language that addresses the inclusion of any generation supply that may impact the Transmission Operator’s “Area.” Proposed revision: “The collection of Transmission Facilities over which the Transmission Operator is responsible for operating, as well as generation, distribution and loads that have power flowing into or from these Facilities.” 2) Add the phrase “connected to the Transmission Operator Area” after any usage of the word “generation” within the requirements (Example: R 1.2.2 could be revised to “Cancellation or recall of outages of Transmission or generation connected to the Transmission Operator Area. 3) Add technical guidance to clarify the entity functions that are considered part of a Transmission Operator Area. Option 1 is Texas RE’s preferred result, but at a minimum, Option 3 should be incorporated by the SDT.
No
1) Attachment 1 contains terms that are not consistent with the language in the requirements. The following comments identify the areas of inconsistency: Section A, Item 2: Attachment 1, Section A. General Responsibilities, Item 2. Notification, last sentence uses the term adjacent RCs. Based on the Rationale for (2) Notification, it appears that the use of the term “adjacent” is aligned with IRO-014-3, Requirement R1 which uses the term. However, EOP-001-1 Requirement R5 uses the term neighboring RCs. Texas RE recommends the term “adjacent” be replaced with “neighboring” in Section A, Item 2. Section B. EEA Levels, 2. EEA 2, 2.2 Declaration Period, last sentence uses the term “impacted” RCs, BAs and TOPs. However, Requirement R5 replaced the term “impacted” with “neighboring.” Texas RE recommends the term “impacted” be replaced with “neighboring.” Section B. EEA Levels, 3. EEA 3, 3.2 Declaration Period, last sentence uses the term “impacted” RCs, BAs and TOPs. However, Requirement R5 replaced the term “impacted” with “neighboring.” Texas RE recommends the term “impacted” be replaced with “neighboring.” Section B. EEA Levels, 3. EEA 3, 3.4.1 Notification of other parties uses the term “impacted” RCs, BAs and TOPs. However, Requirement R5 replaced the term “impacted” with “neighboring.” Texas RE recommends the term “impacted” be replaced with “neighboring.” Section B. EEA Levels, Alert 0 – Termination, 0.1 Notification uses the term impacted RCs, BAs and TOPs. However, Requirement R5 replaced the term “impacted” with “neighboring.” Texas RE recommends the term “impacted” be replaced with “neighboring.” 2) Section B, EEA Levels, 2. EEA 2, 2.1, Texas RE suggests the addition of clarifiying language to more clearly indicate the RC responsibility as follows: “Upon request [of an EEA] from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.” 3) Section B, EEA Levels, 2. EEA 2, 2.4 Texas RE suggests that “Transmission Operator” should be “Transmission Operator(s).” 4) Section B, EEA Levels, 3. EEA 3, Texas RE suggests there is a responsibility missing from the EEA Level 3 list and recommends adding the responsibility of “Sharing information on resource availability” (as listed within EEA Level 2) within EEA Level 3 responsibilities.
No
Requirement R5 VSL language does not match the updated Requirement R5 language. Texas RE recommends that the VSL language be updated to reflect the revised R5 language. The term “impacted” should be removed and replaced with “neighboring.” The R5 VSL update would read as follows: “The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify other [impacted] Reliability Coordinators, Balancing Authorities and Transmission Operators [in its Reliability Coordinator Area, and neighboring Reliability Coordinators] but did not notify within 30 minutes from the time of receiving notification.”
No
Group
Peak Reliability

Jared Shakespeare
No
R5 should have "impacted" or "affected" or "as applicable" language in it so the RC doesn't have to notify ALL BAs/TOPs and adjacent RCs for all emergencies – just those that need to know such information.
No
The notification section should have "impacted" or "affected" or "as applicable" language in it so the RC doesn't have to notify ALL BAs/TOPs and adjacent RCs for all emergencies – just those that need to know such information.
No
Individual
Sergio Banuelos
Tri-State Generation and Transmission Association, Inc.
No
While TSGT agrees that the language in R3 is better the Standard Drafting Team has created a one sided requirement with R4. By not requiring justification or coordination from the RC to the BA/TOP when they feel they have identified a reliabililty risk within the entities Operating Plan. With these changes they have also removed responsibility from the RC to the TOP/BA by not requiring the RC to officially approve the plan yet the TOP/BA must address the RC’s feedback. TSGT suggests the SDT come up with language that promotes a cooperative effort between the TOP/BA and the RC.
Yes
Yes
No
Group
ISO/RTO Council Standards Review Committee (SRC)
Greg Campoli
No
1. The SRC believes that Requirements R1 and R2 require clarification to remove ambiguities regarding the intent discussed in the rationale box and how language within that requirement could be interpreted. As an example, the rationale box associated with Requirement R1 indicates that the sub-requirements of 1.2 are processes, but certain sub-requirements appear to require provisions – not processes. Also, the requirement should address the need to develop “a process to mitigate Emergencies” rather than “a process to prepare for mitigating”. This should be clarified. Additionally, the meaning of “Reduction of Internal Utility Energy Use” remains unclear and should either be clarified or deleted. The SRC therefore proposes the following revisions to address the above concerns: R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies within its Transmission Operator Area. The Operating Plan shall include the following elements, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Emergency Operating Plan; 1.2. Process for notification to the Reliability Coordinator that it is experiencing an operating Emergency and the associated system conditions; 1.3 Processes to mitigate Emergencies, including: 1.3.1. Management of Transmission and generation outages; 1.3.2. Transmission system reconfiguration; 1.3.3. Redispatch of generation request; and 1.3.4. Reliability impacts of extreme weather conditions 1.3.5 Operator-controlled manual Load that respects automatic Load shedding schemes; and are capable of being implemented in a timeframe adequate for mitigating the Emergency. R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the

following elements, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Process for notification to the Reliability Coordinator that it is experiencing a Capacity Emergency or Energy Emergency and the associated system conditions; 2.3 Processes to mitigate Emergencies including: 2.3.1. Requesting an Energy Emergency Alert, per Attachment 1; 2.3.2. Managing generating resources in its Balancing Authority Area to address: 2.3.2.1. Capability and availability; 2.3.2.2. Known fuel supply and inventory concerns; 2.3.2.3. Fuel switching capabilities; and 2.3.2.4. Environmental constraints. 2.3.3. Public appeals for voluntary Load reductions; 2.3.5. Coordination with government agencies regarding known programs that may facilitate energy reductions; 2.3.6. Use of Interruptible Load, curtailable Load and demand response; 2.3.7. Operator-controlled manual Load that respects automatic Load shedding schemes; and are capable of being implemented in a timeframe adequate for mitigating the Emergent; and 2.3.8. Reliability impacts of extreme weather conditions. Corresponding revisions to VSLs and associated measures are also recommended. 2. The SRC believes that Requirement R3 requires streamlining and clarification to ensure clarity. As an example, the SRC is not clear regarding what is meant by “Review each submitted Operating Plan for coordination”. The SRC proposes the following revisions to address the above concerns: R3. Within 30 calendar days of receipt of an Operating Plan to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority, the Reliability Coordinator shall: 3.1.1 Review each submitted Operating Plan: 3.1.1.1 For compatibility and inter-dependency with other Balancing Authorities’ and Transmission Operators’ Operating Plans; and 3.1.1.2. To avoid risk to Wide Area reliability; and 3.1.2. Notify each Balancing Authority and Transmission Operator of the results of its review. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] Corresponding revisions to VSLs and associated measures are also recommended.
No
1. The SRC notes that Subsection 2.3 is redundant with the requirements contained in IRO-014-3. To avoid duplication, it is recommended that this subsection be removed. 2. The SRC notes two minor typographical errors: a. Sections B and subsections 2.2, 3, 3.1, 3.3, and 0.1 appear to contain an inadvertent space in the added term “Reliability Coordinator s”. This space should be removed. b. The third sentence in Section B is not part of a requirement and is, therefore, unnecessary and should be removed. c. It is recommended that the circumstances underlying an EEA 2 be clarified. The following revisions are proposed: Circumstances: • The Balancing Authority is an energy deficient Balancing Authority and o Is no longer able to meet energy requirements. o Has implemented its Operating Plan to mitigate Emergencies. o Is still able to maintain minimum Contingency Reserve requirements. d. Section 3.3.1 appears to contain an inadvertent word “it” before “will immediately take…” This should be removed from Section 3.3.1.
No
The SRC has the following concerns regarding the VSLs/VRFs: a. The SRC agrees with most of the assigned VRFs and VSLs, but have the following concerns: i. The VRF for Requirement R3 should be medium as it is an administrative requirement. b. There lacks a clear demarcation between the HIGH and SEVERE VSLs for Requirement R5. In brief, a HIGH VSL is assigned when the RC notifies others but not within the 30 minute target; whereas the RC is assigned a SEVERE VSL if it failed to notify others. It is unclear as to what time period an RC is assessed “failed to notify”. Is it 1 hour, 2 hours or 24 hours after the declaration of Emergency? Clarification is needed. Accordingly, the SRC suggests that the SDT consider making the VSLs for R5 fully staggered, which would include LOWER, MEDIUM, HIGH and SEVERE VSLs. For example, the LOWER VSL being up to 10 minutes late in notifying others, MEDIUM VSL being up to 20 minutes late, HIGH being up to 30 minutes late and SEVERE being more than 30 minutes late.
Yes
While the SRC agrees that entities need to be forecasting conditions and taking actions to address deficiencies prior to real-time, the SRC disagrees with the revisions made to the term “Energy Emergency”. The posting indicates that revisions were made solely to recognize that Load-Serving Entities are not the only entities that may declare an Energy Emergency. However, additional revisions appear to bring forecasted conditions within the definition of “Energy Emergency”. The SRC assesses that, while the forecasting of potential deficiency conditions is important, use of the term “Energy Emergency” should be reserved for those conditions where an entity is truly “energy deficient” regarding serving its Load obligations, i.e., at an Energy Emergency Alert level 2 or above.

The SRC proposes the following revisions be made to the definition of Energy Emergency: Energy Emergency - A condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide sufficient energy to meet its Load obligations.
Group
Bonneville Power Administration
Andrea Jessup
Yes
Yes
Yes
Yes
BPA requests verification/clarification of R5 notification methodology: Will WECCNet suffice as "electronic communications, or equivalent evidence"? BPA believes it would be unrealistic for the RC to all of the BA/TOPs in its footprint (50-100 or more) within 30 minutes by any any other manner.

Consideration of Comments

Project 2009-03 Emergency Operations

The Project 2009-03 Emergency Operations (EOP) standard drafting team (SDT) thanks all commenters who submitted comments on the standard. These standards were posted for a 45-day public comment period from September 5, 2014 through October 20, 2014. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 36 sets of comments, including comments from approximately 131 different people from approximately 88 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

All comments submitted may be reviewed in their original format on the standard's project page.

If you feel that your comment has been overlooked, please let us know immediately. The SDT has given every comment serious consideration in this process. However, if you feel there has been an error or omission, you can contact the Director of Standards, Valerie Agnew, at 404-446-2566 or at valerie.agnew@nerc.net . In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Standard Processes Manual: http://www.nerc.com/comm/SC/Documents/Appendix_3A_StandardsProcessesManual.pdf

The Industry Segments are:

1 — Transmission Owners

2 — RTOs, ISOs

3 — Load-serving Entities

4 — Transmission-dependent Utilities

5 — Electric Generators

6 — Electricity Brokers, Aggregators, and Marketers

7 — Large Electricity End Users

8 — Small Electricity End Users

9 — Federal, State, Provincial Regulatory or other Government Entities

10 — Regional Reliability Organizations, Regional Entities

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Janet Smith	Arizona Public Service Company	X		X		X	X				
N/A													
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	David Burke	Orange and Rockland Utilities Inc.	NPCC	3
3.	Greg Campoli	New York Independent System Operator	NPCC	2
4.	Kelly Dash	Consolidated Edison Co. of New York, Inc.	NPCC	1
5.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

8.	Michael Jones	National Grid	NPCC	1
9.	Mark Kenny	Northeast Utilities	NPCC	1
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	Bruce Metruck	New York Power Authority	NPCC	6
12.	Silvia Parada Mitchell	NextEra Energy, LLC	NPCC	5
13.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
14.	Robert Pellegrini	The United Illuminating Company	NPCC	1
15.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
16.	David Ramkalawan	Ontario Power Generation, Inc.	NPCC	5
17.	Brian Robinson	Utility Services	NPCC	8
18.	Alan MacNaughton	New Brunswick Power Corporation	NPCC	9
19.	Helen Lainis	Independent Electricity System Operator	NPCC	2
20.	Ayesha Sabouba	Hydro One Networks Inc.	NPCC	1
21.	Brian Shanahan	National Grid	NPCC	1
22.	Wayne Sipperly	New Yor Power Authority	NPCC	5
23.	Ben Wu	Orange and Rockland Utilities Inc.	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

3.	Group	Connie Lowe	Dominion	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Louis Slade	NERC Compliance Policy	SERC	1, 3, 5, 6
2.	Mike Garton	NERC Compliance Policy	NPCC	5
3.	Randi Heise	NERC Compliance Policy	RFC	5, 6

4.	Group	Paul Haase	Seattle City Light	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pawel Krupa	Seattle City Light	WECC	1
2.	Dana Wheelock	Seattle City Light	WECC	3
3.	Hao Li	Seattle City Light	WECC	4
4.	Mike Haynes	Seattle City Light	WECC	5
5.	Dennis Sismaet	Seattle City Light	WECC	6

5.	Group	Joe DePoorter	MRO NERC Standards Review Forum	X	X	X	X	X	X				

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
1.	Amy Casucelli	Xcel Energy	MRO	1, 3, 5, 6
2.	Chuck Wicklund	Otter Tail Power	MRO	1, 3, 5
3.	Dan Inman	Minnkota Power Cooperative	MRO	1, 3, 5, 6
4.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
5.	Kayleigh Wilkerson	Lincoln Electric System	MRO	1, 3, 5, 6
6.	Jodi Jensen	WAPA	MRO	1, 6
7.	Ken Goldsmith	Alliant Energy	MRO	4
8.	Mahmood Safi	Omaha Public Power District	MRO	1, 3, 5, 6
9.	Marie Knox	MISO	MRO	2
10.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
11.	Randi Nyholm	Minnesota Power	MRO	1, 5
12.	Scott Nickels	Rochester Public Utilities	MRO	4
13.	Terry Harbour	MidAmerican Energy	MRO	1, 3, 5, 6
14.	Tom Breene	Wisconsin Public Service	MRO	3, 4, 5, 6
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Dennis Chastain	Tennessee Valley Authority	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	DeWayne Scott		SERC	1
2.	Ian Grant		SERC	3
3.	Brandy Spraker		SERC	5
4.	Marjorie Parsons		SERC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Richard Hoag	FirstEnergycorp	X	X	X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	William Smith	FirstEnergy Corp	RFC	1
2.	Cindy Stewart	FirstEnergy Corp	RFC	3
3.	Doug Hohlbaugh	Ohio Edison	RFC	4
4.	Ken Dressner	FirstEnergy Solutions	RFC	5
5.	Kevin Querry	FitstEnergy Solutions	RFC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Wayne Johnson	Southern Company: Southern Company Services, Inc.; Alabama Power Company;	X		X		X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
			Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing										
N/A													
9.	Group	Brent Ingebrigtson	PPL NERC Registered Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charlie Freibert	LG&E and KU Energy,LLC	SERC	3
2.	Anette Bannon	PPL Generation, LLC	RFC	5
3.		PPL Susquehanna, LLC	RFC	5
4.		PPL Montana, LLC	WECC	5
5.	Brenda Truhe	PPL Electric Utilities Corporation	RFC	1
6.	Elizabeth Davis	PPL EnergyPlus, LLC	MRO	6
7.			NPCC	6
8.			RFC	6
9.			SERC	6
10.			SPP	6
11.			SPP	6

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Phil Hart	Associated Electric Cooperative, Inc.	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	Central Electric Power Cooperative		SERC	1, 3
2.	KAMO Electric Cooperative		SERC	1, 3
3.	M & A Electric Power Cooperative		SERC	1, 3
4.	Northeast Missouri Electric Power Cooperative		SERC	1, 3
5.	N.W. Electric Power Cooperative, Inc.		SERC	1, 3
6.	Sho-Me Power Electric Cooperative		SERC	1, 3

Group/Individual		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Robert Rhodes	SPP Standards Review Group		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ron Gunderson	Nebraska Public Power District	MRO	1, 3, 5

Group/Individual	Commenter	Organization	Registered Ballot Body Segment									
			1	2	3	4	5	6	7	8	9	10

2.	Robert Hirchak	Cleco Power	SPP	1, 3, 5, 6
3.	Stephanie Johnson	Westar Energy	SPP	1, 3, 5, 6
4.	Bo Jones	Westar Energy	SPP	1, 3, 5, 6
5.	Allen Klassen	Westar Energy	SPP	1, 3, 5, 6
6.	Tiffany Lake	Westar Energy	SPP	1, 3, 5, 6
7.	Brandon Levander	Nebraska Public Power District	MRO	1, 3, 5
8.	Shannon Mickens	Southwest Power Pool	SPP	2
9.	James Nail	City of Independence, MO	SPP	3, 5
10.	Jason Smith	Southwest Power Pool	SPP	2
11.	John Stephens	City Utilities of Springfield	SPP	1, 4
12.	Sing Tay	Oklahoma Gas & Electric	SPP	1, 3, 5, 6
13.	J. Scott Williams	City Utilities of Springfield	SPP	1, 4
14.	Bryn Wilson	Oklahoma Gas & Electric	SPP	1, 3, 5, 6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
12. Group	Kathleen Black	DTE Electric			X	X	X					

Additional Member	Additional Organization	Region	Segment Selection
1. Kent Kujala	NERC Compliance	RFC	3
2. Daniel Herring	NERC Training & Standards Development	RFC	4
3. Mark Stefaniak	Merchant Operations	RFC	5

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
13. Group	Michael Lowman	Duke Energy	X		X		X	X				

Additional Member	Additional Organization	Region	Segment Selection
1. Doug Hils			1
2. Lee Schuster			3
3. Dale Goodwine			5
4. Greg Cecil			6

Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
14. Group	Ben Engelby	ACES Standards Collaborators						X				

Additional Member	Additional Organization	Region	Segment Selection
1. Luis Zaragoza	Sunflower Electric Power Corporation	SPP	1
2. Ginger Mercier	Prairie Power, Inc.	SERC	3
3. Shari Heino	Brazos Electric Power Cooperative, Inc.	ERCOT	1, 5

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

	Additional Member	Additional Organization	Region	Segment Selection
4.	Amber Skillern	East Kentucky Power Cooperative	SERC	1, 3, 5
5.	John Shaver	Arizona Electric Power Cooperative/ Southwest Transmission Cooperative, Inc.	WECC	1, 4, 5
6.	Mark Ringhausen	Old Dominion Electric Cooperative	RFC	3, 4
7.	Bill Hutchison	Southern Illinois Power Cooperative	SERC	1, 5
8.	Bob Solomon	Hoosier Energy Rural Electric Cooperative, Inc.	RFC	1

				1	2	3	4	5	6	7	8	9	10
15.	Group	Jared Shakespeare	Peak Reliability	X									
N/A													
16.	Group	Greg Campoli	ISO/RTO Council Standards Review Committee (SRC)		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Matt Goldberg	ISO-NE	NPCC	2
2.	Christina Bigelow	ERCOT	ERCOT	2
3.	Cheryl Moseley	ERCOT	ERCOT	2
4.	Terry Bilke	MISO	MRO	2
5.	Al DiCaprio	PJM	RFC	2
6.	Charles Yeung	SPP	SPP	2
7.	Ali Merimadi	CAISO	WECC	2
8.	Ben Li	IESO	NPCC	2

				1	2	3	4	5	6	7	8	9	10
17.	Group	Andrea Jessup	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jim Burns	Technical Operations	WECC	1

				1	2	3	4	5	6	7	8	9	10
18.	Individual	Leonard Kula	Independent Electricity System Operator		X								
19.	Individual	Brett Holland	Kansas City Power and Light	X		X		X	X				
20.	Individual	Thomas Foltz	American Electric Power	X		X		X	X				
21.	Individual	Denise M Lietz	Puget Sound Energy	X		X		X					
22.	Individual	Joe O'Brien on behalf of David Austin	NIPSCO	X		X		X	X				
23.	Individual	Dave Willis	Idaho Power	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
24.	Individual	Anthony Jablonski	ReliabilityFirst										X
25.	Individual	John Merrell	Tacoma Power	X		X	X	X	X				
26.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
27.	Individual	Matthew Beilfuss	We Energies			X	X	X					
28.	Individual	Joshua Andersen	Salt River Project	X		X		X	X				
29.	Individual	Jo-Anne Ross	Manitoba Hydro	X		X		X	X				
30.	Individual	Chris Scanlon	Exelon Companies	X		X		X	X				
31.	Individual	Sonya Green-Sumpter	South Carolina Electric & Gas	X		X		X	X				
32.	Individual	Catherine Wesley	PJM Interconnection		X								
33.	Individual	Matthew F. Goldberg	ISO New England Inc.		X								
34.	Individual	Gregory Campoli	New York Independent System Operator		X								
35.	Individual	Karin Schweitzer	Texas Reliability Entity										X
36.	Individual	Sergio Banuelos	Tri-State Generation and Transmission Association, Inc.	X		X		X					

If you support the comments submitted by another entity and would like to indicate you agree with their comments, please select "agree" below and enter the entity's name in the comment section (please provide the name of the organization, trade association, group, or committee, rather than the name of the individual submitter).

Summary Consideration: None required for this section.

Organization	Agree	Supporting Comments of "Entity Name"
N/A	N/A	N/A

1. **EOP-011-1. Do you agree with the changes made to EOP-011-1? If not, please specifically identify those changes that you do not agree with, the basis for your disagreement, and your proposed revisions to the language at issue**

Summary Consideration: The EOP SDT appreciates all of the comments received.

Puget Sound Energy provided a comment requesting the EOP SDT to consider revision of the NERC glossary defined term “Emergency.” The EOP SDT appreciates the suggestion; however, the drafting team has determined that the language is appropriate as drafted. The use of the NERC defined glossary term “Emergency” provides clarity regarding the types of events and situations to be included in the Operating Plan(s).

Duke Energy provided a revision suggestion to the revised defined term Energy Emergency to include “…or balancing obligations respectively.” Energy Emergency results from an inability to serve Load; it is not necessarily dependent upon balancing issues, therefore, the drafting team elected to retain the language as drafted.

A number of stakeholders commented about multiple plans. It was the EOP SDT’s intent in Requirements R1 and R2 that the Operating Plan(s) could be one plan or multiple plans, as stated in the Rationale boxes for these requirements; but agrees with Tennessee Valley Authority that consistency is needed and has made the clarifying revision “Plan(s)” throughout the standard. In addition, ACES Standards Collaborators requested clarification regarding entities that serve as both a Balancing Authority and Transmission Operator, if a single Operating Plan is acceptable under the drafted Requirements R1 and R2. It is the intent of the EOP SDT that if an entity is both a Balancing Authority and a Transmission Operator, they can have a single Operating Plan to address both the Balancing Authority and Transmission Operator aspects of addressing an Emergency. If an entity is both a Balancing Authority and Transmission Operator and prefer to have separate Operating Plans, that is acceptable as well; it is the intent of the EOP SDT for this determination to be made by the entity.

For Requirement R1, Texas Reliability Entity submitted a comment for clarification of entity functions that are considered part of a Transmission Operator Area. The intent of the drafting team is that a specific generator may not be included in a Transmission Operator Area, but a specific generator must be within the metered boundaries of a Balancing Authority Area. Some Transmission Operators cancel or recall transmission and generation outages and some Transmission Operators do not. The Operating Plan(s) should address the entity’s specific situation.

SPP offered revised language revisions to Requirement R1 Part 1.2.5. The EOP SDT appreciates the comment, but will retain the existing language of Requirement R1 Part 1.2.5.; the drafting team believes it provides the necessary focus. Duke Energy commented as well to Requirement R1 Part 1.2.5., stating their understanding of the language “capable of being implemented in a timeframe adequate for mitigating the Emergency” in the requirement part as: “It is our understanding that this phrase provides an entity the flexibility to identify on its own, the timeframes it deems adequate for mitigating emergencies within their Operating Plan." The EOP SDT thanks you for your comment and confirms that your interpretation of Requirement R1 Part 1.2.5. is correct.

American Electric Power submitted the following comment regarding Requirement R1 Parts 1.2.2. and 1.2.4.: "…AEP does not believe it is within the TOP's jurisdiction to perform such actions within their Transmission Operator Plan. Rather, AEP believes it would be the BA's responsibility to recall generation outages or redispatch generation." The EOP SDT recognizes that it may be necessary for both the Balancing Authority and Transmission Operator to notify the GOP for Emergency conditions, which can be both Capacity/Energy or Transmission related. Therefore, the EOP SDT has retained the language as drafted. TLR or market-based congestion management processes do not apply throughout North America.

The EOP SDT retained the requirement language to include "provisions" in Requirement R1 Part 1.2.5 and Requirement R2 Part 2.3.7 due to a number of stakeholder comments on the previous posting. WE Energies and SPP requested clarification and language revision suggestions of Requirement R2 Part 2.2.8. The EOP SDT's intent in Requirement R2 Part 2.2.8. is that this related to "provisions for operator-controlled manual Load shedding…" This allows for the Operating Plan(s) regardless of whether the entity is a vertically integrated utility or not. The EOP SDT believes the existing language provides the necessary intent.

In response to comments received from Duke Energy, ACES Standards Collaborators, American Electric Power, ReliabilityFirst, WE Energies, and Tri-State Generation and Transmission Association, Inc., the EOP SDT believes it is important to minimize the overlap with automatic Load shedding and will retain the language as drafted. In addition, the drafting team will propose language revisions to the RSAW to include a review of the process aspect of Load shedding rather than the actual amount of Load that might be shed during an Emergency.

NIPSCO requested clarification of the justification of Long-term Planning horizons for Requirements R1 and R2. In some cases, an entity may have planning horizon studies which require Operating Plan(s) to be developed to mitigate or address them. The language of Requirements R1 and R2 says the plans are to be developed, maintained, and implemented. In addition, NIPSCO requested clarification on the distinction between TOP-002-4/TOP-001-3 and EOP-011-1 Operating Plans. In response, the EOP SDT would like to make this clarification by stating that TOP-002-4/TOP-001-3 are not the same operating plans, as those plans deal with addressing SOLs, while EOP addresses Emergencies.

Additional clarification was requested for Requirement R2 Part 2.2.3. The EOP SDT maintains that Requirement R2 Part 2.2.3, as drafted, provides the necessary details and clarity regarding generating resources.

EOP SDT drafted Requirements R1 and R2 to correlate with the general industry consensus regarding the intent of "extreme weather conditions." The EOP SDT would like to thank PPL NERC Registered Affiliates for their comments; however, each item of the requirement parts in Requirements R1 and R2 need to be addressed, and state where they are not applicable, in the Operating Plan(s), the language as drafted was retained.

DTE Electric, ACES Standards Collaborators, SRC, American Electric Power, ReliabilityFirst, WE Energies, and Tri-State Generation and Transmission Association, Inc. submitted comments requesting clarification, as well as suggesting revisions of Requirement R3 and Requirement R3 Parts 3.1. and 3.1.3. The drafting team has revised Requirement R3 and Requirement R3 Parts 3.1. and 3.1.3 to provide clarification and notification specificity, as follows:

"R3. The Reliability Coordinator shall~~, within 30 calendar days of receipt,~~ review each Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans.

3.1. Within 30 calendar days of receipt, ~~The~~ the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified."

The EOP SDT augmented Requirement R3 Part 3.1.3. to provide clarity to the required actions of the Reliability Coordinator. Specifically, the SDT added language to ensure that the Reliability Coordinator specifies a time frame for resubmittal of the Operating Plan(s) as needed. The intent of the SDT, reinforced by the language of other requirements, does not change with inclusion of this language, as Requirement R4 anticipates a time period will have been specified by the Reliability Coordinator upon the discovery of a reliability risk. Thus, this change is consistent with the scope, applicability, and intent of the previous draft of EOP-011-1.

Duke Energy provided a suggestion to combine Requirement R3 and Requirement R4. Requirement R3 and Requirement R4 were written with the EOP SDT's intent to not be prescriptive, while still providing the reliability requirements necessary. The EOP SDT maintains that, rather than combining the requirements, they should remain separate.

Several commenters requested clarification regarding the coordination of Operating Plan(s) under Requirement R3. When reviewing the Operating Plan(s), the RC is looking for deficiencies, inconsistencies, or conflicts between the submitted plans that would cause further degradation to BES during Emergency conditions.

The EOP SDT notes that a Capacity or Energy Emergency is a subset of an operating Emergency and has retained the term "operating Emergencies" in Requirement R3.

Manitoba Hydro provided language revision suggestions for Requirement R4 to include the language: "make a good faith attempt to address." The EOP SDT believes that the coordination should resolve any reliability risks identified during the review. The RC has the authority to require a TOP or BA to take actions in cases of Emergency.

To address the comments received by SPP, NIPSCO, WE Energies and Salt River Project regarding maintenance of Operating Plan(s) in EOP-011-1, the EOP SDT drafted the standard to allow flexibility to the Transmission Operator and Balancing Authority with regards to frequency of maintenance on their plan(s). The intent is to ensure that their plan(s) are maintained so that they are available for implementation to address an Emergency. The Measure also includes language regarding maintenance: "… evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained."

The EOP SDT received comments requesting a clarification of periodic reviews on Operating Plan(s) to mitigate Emergencies. The EOP SDT does not believe that there needs to be a periodic review on the Operating Plan(s) and declines to include this requirement in the standard.

Comments were received from Associated Electric Cooperative, Inc. and ReliabilityFirst requesting clarification of the EOP SDT's intent in the use of the term "implement." An Operating Plan is implemented by carrying out its stated actions, which the drafting team intended to be used consistently with the use of this term in similar standards.

In response to comments received, the EOP SDT has revised Attachment 1 to replace "adjacent" with "neighboring."

SPP and MRO NERC Standards Forum requested the language "impacted" be re-inserted into the draft standard to provide clarity. The EOP SDT retained "neighboring" and has removed "impacted" to ensure notifications for situational awareness. The EOP SDT believes that there is a reliability benefit to notifying other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators.

Duke Energy provided the suggested language revision to Requirement R5: "Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority, as identified in its respective Operating Plan shall notify, within 30 minutes from the time of receiving notification, affected Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and affected neighboring Reliability Coordinators." The EOP SDT believes the suggested changes assume that the Reliability Coordinator has an Operating Plan, this is not necessarily an accurate assumption. The suggested revision was not made.

The EOP SDT notes that Requirement R5 requires notifications to Transmission Operators, Balancing Authorities and neighboring Reliability Coordinators. IRO-014-3 limits the notification to "other impacted" RC's. The EOP SDT believes, in Requirement R5, that there is a reliability benefit to notifying other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators; such notification provides situational awareness for those entities.

Requirement R6, as SPP correctly commented on, is a holdover from EOP-002-3.1, Requirement R8. The rationale box for Requirement R6 is incorrect and has been removed.

The EOP SDT has made corrective revisions to suggested punctuation, grammar and syntax in EOP-011-1 where merited.

Organization	Yes or No	Question 1 Comment
Tennessee Valley Authority	No	Standard requirements should reflect Operating Plan(s), not Operating Plan. Rationale states that there can be multiple plans. Recommend uses “Plan(s)” in place of “Plan” consistently through the Standard. R2.2.3.1 and subrequirements and R2.2.9. need more clarification. Webinar discussion implied the Balancing Authority needed to have awareness of generator availability and constraints. Recommend changing R.2.2.3 to remove “Managing generating resources “ and use “Maintain awareness of generator capability and availability” and delete “to address” and the subrequirements. Recommend changing R2.2.9 by inserting “Maintain awareness of” at beginning of requirement. R3.1.1. should be clarified by inserting “within its Reliability Coordinator Area” at the end of the requirement. R3.1.3 should be clarified by inserting “submitting” after “Notify each”.
FirstEnergycorp	No	FIRSTENERGY supports the RSC comments which are reflected below but was not provided as an option before the ballots.We agree with most of the changes, but have a difficulty understanding Part 3.1.2., which stipulates that:3.1.2. Review each submitted Operating Plan for coordination to avoid risk to Wide Area reliability; andWe are not clear on what it means by “Review each submitted Operating Plan for coordination”. Does it mean the RC, when reviewing the Operating Plan, needs to look for elements or confirmation of coordination between the submitting entity and other BAs and TOPs in the RC area? Or is it that the review needs to yield (and therefore the RC shall ask for or direct) coordination among the submitting

Organization	Yes or No	Question 1 Comment
		entity and other BAs and TOPs in the RC area? We believe some wording change is needed to clarify the intent of this Part 3.1.2.
PPL NERC Registered Affiliates	No	These comments are submitted on behalf of the following PPL NERC Registered Affiliates: LG&E and KU Energy, LLC; PPL Electric Utilities Corporation, PPL EnergyPlus, LLC; PPL Generation, LLC; PPL Susquehanna, LLC; and PPL Montana, LLC. The PPL NERC Registered Affiliates are registered in six regions (MRO, NPCC, RFC, SERC, SPP, and WECC) for one or more of the following NERC functions: BA, DP, GO, GOP, IA, LSE, PA, PSE, RP, TO, TOP, TP, and TSP.The PPL NERC Registered Affiliates support the revisions that have occurred between draft 2 and this draft 3 of Attachment A. However, additional improvements and clarification could be made. The term “extreme weather conditions” used in R1 Part 1.2.6 and R2 Part 2.2.9, is subjective. Auditors and entities may consider different types of weather “extreme.” Further description or guidance is needed to enable compliance. In addition, unlike R1 Parts 1.2.1 thru 1.2.5 and R2 Parts 2.2.1 thru 2.2.8, it is not clear how “Reliability impacts of extreme weather conditions” is a process (in part because there is no verb before reliability). If it is the SDT’s intention that Operating Plans to mitigate Emergencies include preparations for extreme weather conditions, PPL Companies recommend the following changes be made to R1 and R2: - R1 Part 1.2.6 should be moved above Part 1.2 and read, “Preparation for the reliability impacts of extreme weather conditions;” - R2 Part 2.2.9 should be moved above R2 Part 2.2 and read, “Preparation for the reliability impacts of extreme weather conditions.” Accordingly, the numbering of Parts 1.2 and 2.2 as they appear in draft 3 would become 1.3 and 2.3.
Associated Electric Cooperative, Inc.	No	AECI agrees with SPP Comments
SPP Standards Review Group	No	R1/R2 - While we have seen the ‘develop, maintain and implement’ language in other standards, we continue to be a bit unsure just how we

Organization	Yes or No	Question 1 Comment
		are to use this terminology in practice. In some situations, implement means have a procedure available for use on the control room floor and that the operators have been trained on the procedure. In other situations, and it appears to us that EOP-011-1 is one of those situations, implement refers to activating the plan, process or procedure. We believe NERC needs to address what appears to be a lack of consistency as applied across the set of Reliability Standards. Another issue with this standard is the lack of direction for maintenance of an Operating Plan. Perhaps the SDT could provide additional clarification in the form of a Rationale Box which would be of assistance to the industry. R1.2.1 - Change 'Notification to the Reliability Coordinator...' to 'Notification of its Reliability Coordinator...'.R1.2.5 - We appreciate the changes that the SDT incorporated to clarify the overlap between manual and automatic Load shedding. However, the rewrite may have swung the focus of the requirement away from manual Load shedding and onto the overlap. The focus should be on manual Load shedding. We offer the following to replace the existing sentence: 'Operator-controlled manual Load shedding that is capable of being implemented in a timeframe adequate for mitigating the Emergency. Manual Load shedding programs shall contain provisions for minimizing overlap with automatic Load shedding.'Rationale for Requirement R1 - In the last line of the 3rd paragraph, replace '...how you will make a notification to the...' with '...when the Transmission Operator must notify its...'.R2-Insert 'within its Balancing Authority Area' at the end of the 1st sentence of the requirement.R2.2.1- Change 'Notification to the Reliability Coordinator...' to 'Notification of its Reliability Coordinator...'.R2.2.8 - Again, we appreciate the changes that the SDT incorporated to clarify the overlap between manual and automatic Load shedding. However, the rewrite may have swung the focus of the requirement away from manual Load shedding and onto the overlap. The focus should be on manual Load shedding. We offer the following to

Organization	Yes or No	Question 1 Comment
		replace the existing sentence: ‘Operator-controlled manual Load shedding that is capable of being implemented in a timeframe adequate for mitigating the Emergency. Manual Load shedding programs shall contain provisions for minimizing overlap with automatic Load shedding.’Rational for Requirement R2 - Delete ‘Emergency’ in ‘Emergency Operating Plan’ in the last line of the 1st paragraph. In the 4th line of the 6th paragraph, set the phrase ‘as much as possible’ off with commas as was done in the Rationale for Requirement R1.R3 - Since the review of the Operating Plans does not specifically mitigate Emergencies, we recommend the following language for Requirement R3: ‘...shall review each Operating Plan to coordinate the planned actions to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority...’. Also, hyphenate ‘30-calendar days’.R3.1.1 - Add ‘within its Reliability Coordinator Area’ at the end of the Subpart.R3.1.2 - Modify the Subpart to the following: ‘Review each submitted Operating Plan for coordination to avoid reliability risks within its Wide Area; and’R3.1.3 - Add ‘of its review’ at the end of the Subpart.Rationale for R3 - In the 3rd line, change ‘require’ to ‘requires’. Capitalize ‘Emergencies’ in the last line.M3 - Hyphenate ‘30-calendar days’.M4 - Replace ‘emails’ in the 2nd line with ‘e-mails’ to make it consistent with the usage in M3.R5/M5 - Insert the phrase ‘within its Reliability Coordinator Area’ after ‘Balancing Authority’ in the 2nd line of this requirement. This makes the Reliability Coordinator only accountable for notifications received from within its own footprint. ‘Neighboring’ is used in conjunction with Reliability Coordinator at the end of this requirement. ‘Adjacent’ is used in Sections 3.2 and 0.1 of Attachment 1. Please be consistent with the usage. Additionally, the term ‘impacted’ has been deleted from the requirement. Rather than notifying only the impacted Balancing Authorities and Transmission Operators within its footprint, the Reliability Coordinator must now notify all Balancing Authorities and Transmission Operators within its footprint. When asked

Organization	Yes or No	Question 1 Comment
		about this during the webinar, the SDT response was that it was a cleaner solution to the notification issue and that all Reliability Coordinators are notified if the RCIS is used. While both of these responses are correct. The use of impacted does not detract from the requirement at all. There's a good possibility that all Balancing Authorities may be notified through reserve sharing arrangements or during the search for available energy. As mentioned all Reliability Coordinators will be automatically notified if the RCIS is used, so nothing is lost there. However, if the Reliability Coordinator footprint is spread over a large geographical area, requiring the Reliability Coordinator to notify all Transmission Operators within its Reliability Coordinator Area may be excessive, especially considering that Transmission assistance from one Transmission Operator to another some distance away may not be feasible. We suggest retaining the term 'impacted'. Modify Measure M5 to be consistent with the suggested changes to Requirement R5.The language in Reqiurement R5 does not require a Reliablity Coordinator to notify impacted Balancing Authorities or Transmission Operators within its Reliability Coordinator Area of Emergencies occurring on the seams with other Reliability Coordinators. We recommend the following to ensure this notification occurs. 'Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area or neighboring Reliability Coordinator shall notify, within 30 minutes from the time of receiving notification, other impacted Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring (or adjacent) Reliability Coordinators.' Rationale for R6 - The SDT states that this requirement was created to address the FERC directives but isn't this requirement really a holdover from EOP-002-3.1, R8?
DTE Electric	No	Comments: The language in R3 requires the RC to review plans within 30 days but does not specify a time limit to notify the BA or TOP. R3 also does

Organization	Yes or No	Question 1 Comment
		not require the RC to specify a time period to the BA or TOP to address issues but R4 requires those issues to be addressed in a specified time frame. Suggested new language for R3:R3. The Reliability Coordinator, within 30 calendar days of receipt, shall review each Operating Plan to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. 3.1. The Reliability Coordinator review shall consist of the following actions: 3.1.1. Review each submitted Operating Plan on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans; 3.1.2. Review each submitted Operating Plan for coordination to avoid risk to Wide Area reliability; 3.1.3. Notify each Balancing Authority and Transmission Operator of the results; and3.1.4. If risks are identified, specify a time frame for the affected Balancing Authority or Transmission Operator to address the risks and resubmit its plan. [Violation Risk Factor: High] [Time Horizon: Operations Planning]
Duke Energy	No	(1) Duke Energy suggests the following revision to requirement 1.2.5:"1.2.5. Provisions for operator-controlled manual Load shedding that are capable of being implemented in a timeframe adequate for mitigating the Emergency; and..."We believe that it will be difficult to demonstrate compliance to an auditor that an entity has provisions in place to "minimize the overlap with automatic Load shedding" which are adequate. This phrase makes the requirement subjective, and would make measuring compliance for auditors difficult due to the varying nature with which each entity could approach meeting compliance with this requirement.(2) Could the SDT please clarify our understanding of the phrase "capable of being implemented in a timeframe adequate for mitigating the Emergency..." within requirement 1.2.5? It is our understanding that this phrase provides an entity the flexibility to identify on its own, the timeframes it deems adequate for mitigating emergencies within their Operating Plan. Is this

Organization	Yes or No	Question 1 Comment
		correct?(3) Duke Energy suggests the following revision to the definition of Energy Emergency:"Energy Emergency - A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its expected Load or balancing obligations respectively."Per the NERC Functional Model, the LSE has the obligation to serve load and the BA has the obligation to maintain balance. We believe the addition of "Load or balancing obligations respectively" more accurately distinguishes the separate responsibilities of a LSE or BA during an Energy Emergency. .(4) Duke Energy suggests the following revision to requirement 2.2.8:"2.2.8. Provisions for operator-controlled manual Load shedding that are capable of being implemented in a timeframe adequate for mitigating the Emergency; and..."We believe that it will be difficult to demonstrate compliance to an auditor that an entity has provisions in place to "minimize the overlap with automatic Load shedding" which are adequate. This phrase makes the requirement subjective, and would make measuring compliance for auditors difficult due to the varying nature with which each entity could approach meeting compliance with this requirement.(5) Duke energy suggests combining Requirements 3 and 4 as follows:"Each RC and Balancing Authorities and Transmission Operators within its RC Area shall review and revise the BA and TOP Operating Plans as necessary for coordination." We believe the proposed R3 and R4 are too prescriptive in nature and may not address the intent of the SDT of promoting coordination of the Operating Plans among the listed functions. We feel that our suggested language captures more clearly the desired coordination as intended by the SDT.(6) Duke Energy suggests the following revision to requirement 5:"Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority, as identified in its respective Operating Plan shall notify, within 30 minutes from the time of receiving notification, affected Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and affected

Organization	Yes or No	Question 1 Comment
		neighboring Reliability Coordinators."We believe the NERC definition of Emergency is too broad within the context of this requirement. Per the NERC definition of Emergency, any tripping of generation or transmission line that "requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System" would be subject to notification. This would be extremely burdensome for the RC(s), BA(s), and TOP(s). We believe the intent is for the RC to notify affected parties during an event that would put the reliability of the BES at risk. We believe our suggested language narrows the scope to only those events that have that very impact. We also believe that this was the intent of the SDT and not to require that every action taken by a BA/TOP prompt notifications to all BA(s) and TOP(s) within its RC area as well as neighboring RC(s). (7) We ask the EOP SDT to distinguish the differences between EOP-011-1 R5 and IRO-014-3 R3. As written, we believe the 2 requirements listed are similar and would create double jeopardy.
ACES Standards Collaborators	No	(1) We thank the drafting team for modifying Requirement R1 by requiring an Operating Plan rather than an Emergency Operating Plan. (2) If an entity is registered as both a BA and a TOP, would they need two operating plans to address the differences in R1 and R2? If so, we recommend revising these requirements to eliminate duplicative efforts for compliance purposes.(3) For Requirement R3, Part 3.1.3, is there a time frame in which the RC must notify each BA and TOP? Requirement R3 states that the RC must review the Operating Plan within 30 calendar days of receipt, but there is no deadline to provide notice to the submitting entity.(4) For Requirement R4, there are concerns with the timeframes to update and resubmit modified Operating Plans. The requirement should include 30 calendar days of receipt, unless the RC mandates the change to be made sooner. Without any specific timeline, this requirement is difficult to measure what a reasonable time frame would be.(5) We disagree with

Organization	Yes or No	Question 1 Comment
		using the term "minimizes" in Parts 1.2.5 and 2.2.8. This implies that an optimal solution is required. While we agree it does makes sense to be thoughtful in the selection of loads for manual load shed, it simply may not be possible to avoid shedding loads that can also be shed via UFLS in many cases. For instance, there could be many critical loads (i.e. fire and police stations, army bases, hospitals) that prevent this and the system operator should not be burdened in a real-time Emergency with this "minimization" issue when they should be focused on mitigating the Emergency. Also, transmission Emergencies may require loads in a load pocket that has many UFLS relays to be shed. We suggest that Parts 1.2.5 and 2.2.8 be struck in their entirety and to cover this concept in the guidelines sections. The last paragraph in the rationale box for R1 and second to last paragraph for the rationale box for R2 both that the goal is to "minimize as much as possible." This is inconsistent with the language of the requirement which requirements minimization. (6) Requirement R3 is inconsistent with Requirement R2. The requirement compels the RC to review Operating Plans "to mitigate operating Emergencies." R1 uses the term operating Emergencies. R2 does not but rather uses Capacity and Energy Emergencies. R3 should be made consistent with the language in R2.
Peak Reliability	No	R5 should have "impacted" or "affected" or "as applicable" language in it so the RC doesn't have to notify ALL BAs/TOPs and adjacent RCs for all emergencies - just those that need to know such information.
ISO/RTO Council Standards Review Committee (SRC)	No	1. The SRC believes that Requirements R1 and R2 require clarification to remove ambiguities regarding the intent discussed in the rationale box and how language within that requirement could be interpreted. As an example, the rationale box associated with Requirement R1 indicates that the sub-requirements of 1.2 are processes, but certain sub-requirements appear to require provisions - not processes. Also, the requirement should address the need to develop "a process to mitigate Emergencies" rather

Organization	Yes or No	Question 1 Comment
		than “a process to prepare for mitigating”. This should be clarified. Additionally, the meaning of “Reduction of Internal Utility Energy Use” remains unclear and should either be clarified or deleted. The SRC therefore proposes the following revisions to address the above concerns:R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate operating Emergencies within its Transmission Operator Area. The Operating Plan shall include the following elements, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Emergency Operating Plan; 1.2. Process for notification to the Reliability Coordinator that it is experiencing an operating Emergency and the associated system conditions; 1.3 Processes to mitigate Emergencies, including: 1.3.1. Management of Transmission and generation outages; 1.3.2. Transmission system reconfiguration; 1.3.3. Redispatch of generation request; and 1.3.4. Reliability impacts of extreme weather conditions 1.3.5 Operator-controlled manual Load that respects automatic Load shedding schemes; and are capable of being implemented in a timeframe adequate for mitigating the Emergency. R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan shall include the following elements, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan; 2.2. Process for notification to the Reliability Coordinator that it is experiencing a Capacity Emergency or Energy Emergency and the associated system conditions; 2.3 Processes to mitigate Emergencies including: 2.3.1. Requesting an Energy Emergency Alert, per Attachment 1; 2.3.2. Managing generating resources in its Balancing Authority Area to address: 2.3.2.1. Capability and availability; 2.3.2.2. Known fuel supply and

Organization	Yes or No	Question 1 Comment
		inventory concerns; 2.3.2.3. Fuel switching capabilities; and 2.3.2.4. Environmental constraints. 2.3.3. Public appeals for voluntary Load reductions; 2.3.5. Coordination with government agencies regarding known programs that may facilitate energy reductions; 2.3.6. Use of Interruptible Load, curtailable Load and demand response; 2.3.7. Operator-controlled manual Load that respects automatic Load shedding schemes; and are capable of being implemented in a timeframe adequate for mitigating the Emergent; and 2.3.8. Reliability impacts of extreme weather conditions. Corresponding revisions to VSLs and associated measures are also recommended.2. The SRC believes that Requirement R3 requires streamlining and clarification to ensure clarity. As an example, the SRC is not clear regarding what is meant by "Review each submitted Operating Plan for coordination". The SRC proposes the following revisions to address the above concerns:R3. Within 30 calendar days of receipt of an Operating Plan to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority, the Reliability Coordinator shall:3.1.1 Review each submitted Operating Plan: 3.1.1.1 For compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans; and3.1.1.2. To avoid risk to Wide Area reliability; and 3.1.2. Notify each Balancing Authority and Transmission Operator of the results of its review. [Violation Risk Factor: Medium] [Time Horizon: Operations Planning] Corresponding revisions to VSLs and associated measures are also recommended.
Independent Electricity System Operator	No	We agree with most of the changes, but have a difficulty understanding Part 3.1.2., which stipulates that:3.1.2. Review each submitted Operating Plan for coordination to avoid risk to Wide Area reliability; andWe are not clear on what it means by "Review each submitted Operating Plan for coordination". Does it mean the RC, when reviewing the Operating Plan, needs to look for elements or confirmation of coordination between the submitting entity and other BAs and TOPs in the RC area? Or is it that the

Organization	Yes or No	Question 1 Comment
		review needs to yield (and therefore the RC shall ask for or direct) coordination among the submitting entity and other BAs and TOPs in the RC area? We believe some wording change is needed to clarify the intent of this Part 3.1.2.
Kansas City Power and Light	No	R1/R2 - While we have seen the 'develop, maintain and implement' language in other standards, we continue to be a bit unsure just how we are to use this terminology in practice. In some situations, implement means have a procedure available for use on the control room floor and that the operators have been trained on the procedure. In other situations, and it appears to us that EOP-011-1 is one of those situations, implement refers to activating the plan, process or procedure. We believe NERC needs to address what appears to be a lack of consistency as applied across the set of Reliability Standards. Another issue with this standard is the lack of direction for maintenance of an Operating Plan. Perhaps the SDT could provide additional clarification in the form of a Rationale Box which would be of assistance to the industry. R1.2.1 - Change 'Notification to the Reliability Coordinator...' to 'Notification of its Reliability Coordinator...'.R1.2.5 - We appreciate the changes that the SDT incorporated to clarify the overlap between manual and automatic Load shedding. However, the rewrite may have swung the focus of the requirement away from manual Load shedding and onto the overlap. The focus should be on manual Load shedding. We offer the following to replace the existing sentence: 'Operator-controlled manual Load shedding that is capable of being implemented in a timeframe adequate for mitigating the Emergency. Manual Load shedding programs shall contain provisions for minimizing overlap with automatic Load shedding.'Rationale for Requirement R1 - In the last line of the 3rd paragraph, replace '...how you will make a notification to the...' with '...when the Transmission Operator must notify its...'.R2-Insert 'within its Balancing Authority Area' at the end of the 1st sentence of the requirement.R2.2.1- Change 'Notification

Organization	Yes or No	Question 1 Comment
		to the Reliability Coordinator...’ to ‘Notification of its Reliability Coordinator...’.R2.2.8 - Again, we appreciate the changes that the SDT incorporated to clarify the overlap between manual and automatic Load shedding. However, the rewrite may have swung the focus of the requirement away from manual Load shedding and onto the overlap. The focus should be on manual Load shedding. We offer the following to replace the existing sentence: ‘Operator-controlled manual Load shedding that is capable of being implemented in a timeframe adequate for mitigating the Emergency. Manual Load shedding programs shall contain provisions for minimizing overlap with automatic Load shedding.’Rational for Requirement R2 - Delete ‘Emergency’ in ‘Emergency Operating Plan’ in the last line of the 1st paragraph. In the 4th line of the 6th paragraph, set the phrase ‘as much as possible’ off with commas as was done in the Rationale for Requirement R1.R3 - Since the review of the Operating Plans does not specifically mitigate Emergencies, we recommend the following language for Requirement R3: ‘...shall review each Operating Plan to coordinate the planned actions to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority...’. Also, hyphenate ‘30-calendar days’.R3.1.1 - Add ‘within its Reliability Coordinator Area’ at the end of the Subpart.R3.1.2 - Modify the Subpart to the following: ‘Review each submitted Operating Plan for coordination to avoid reliability risks within its Wide Area; and’R3.1.3 - Add ‘of its review’ at the end of the Subpart.Rationale for R3 - In the 3rd line, change ‘require’ to ‘requires’. Capitalize ‘Emergencies’ in the last line.M3 - Hyphenate ‘30-calendar days’.M4 - Replace ‘emails’ in the 2nd line with ‘e-mails’ to make it consistent with the usage in M3.R5/M5 - Insert the phrase ‘within its Reliability Coordinator Area’ after ‘Balancing Authority’ in the 2nd line of this requirement. This makes the Reliability Coordinator only accountable for notifications received from within its own footprint. ‘Neighboring’ is used in conjunction with Reliability Coordinator at the end of this

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		requirement. ‘Adjacent’ is used in Sections 3.2 and 0.1 of Attachment 1. Please be consistent with the usage. Additionally, the term ‘impacted’ has been deleted from the requirement. Rather than notifying only the impacted Balancing Authorities and Transmission Operators within its footprint, the Reliability Coordinator must now notify all Balancing Authorities and Transmission Operators within its footprint. When asked about this during the webinar, the SDT response was that it was a cleaner solution to the notification issue and that all Reliability Coordinators are notified if the RCIS is used. While both of these responses are correct. The use of impacted does not detract from the requirement at all. There’s a good possibility that all Balancing Authorities may be notified through reserve sharing arrangements or during the search for available energy. As mentioned all Reliability Coordinators will be automatically notified if the RCIS is used, so nothing is lost there. However, if the Reliability Coordinator footprint is spread over a large geographical area, requiring the Reliability Coordinator to notify all Transmission Operators within its Reliability Coordinator Area may be excessive, especially considering that Transmission assistance from one Transmission Operator to another some distance away may not be feasible. We suggest retaining the term ‘impacted’. Modify Measure M5 to be consistent with the suggested changes to Requirement R5.The language in Reqiurement R5 does not require a Reliablity Coordinator to notify impacted Balancing Authorities or Transmission Operators within its Reliability Coordinator Area of Emergencies occurring on the seams with other Reliability Coordinators. We recommend the following to ensure this notification occurs. ‘Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area or neighboring Reliability Coordinator shall notify, within 30 minutes from the time of receiving notification, other impacted Balancing Authorities and Transmission Operators in its Reliability

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		Coordinator Area, and neighboring (or adjacent) Reliability Coordinators.' Rationale for R6 - The SDT states that this requirement was created to address the FERC directives but isn't this requirement really a holdover from EOP-002-3.1, R8?
American Electric Power	No	R1.2.2 and R1.2.4 specifies generation actions to be taken the Transmission Operator. These requirements hold the TOP responsible for "cancellation or recall of Transmission and generation outages" and the "Redispatch of generation request". AEP does not believe it is within the TOP's jurisdiction to perform such actions within their Transmission Operator Plan. Rather, AEP believes it would be the BA's responsibility to recall generation outages or redispatch generation. AEP recommends that R.1.2.2 be changed so the BA is solely responsible for such actions, perhaps by breaking out the generation actions from R1 and making them separate from the transmission actions (possibly by adding them to the R2 requirements where the BA is responsible).In regard to R1.2.2 and R1.2.4, AEP believes the BA needs to be responsible for generation outages and the redispatch of generation. For the TOP, existing TLR or market based congestion management processes would re-dispatch generation. In an Emergency event where a generator would need redispatced for a local transmission problem, the TOP may need to contact the Reliability Coordinator. R1.2.5 could have a large impact on Transmission Operators' installed base of manual load shedding / automatic Load shedding systems. AEP recommends the SDT take a poll on the impact using the Transmission Forum. R4 mentions a time period specified by its Reliability Coordinator. AEP believes this should incorporate a working dialog between the Reliability Coordinator and the Transmission Operator and Balancing Authority. As such AEP believes a *mutually agreed time period* would be more appropriate. Such language is used in the EOP 005-2 standard.

Organization	Yes or No	Question 1 Comment
Puget Sound Energy	No	The standard drafting team's changes resulted in a much better standard overall. However, the team did not make any change to the use of the defined term Emergency. Since this term is broad enough to include most transmission system faults, it is over inclusive and could impose a significant burden on entities as they try to demonstrate implementation of the Operating Plan. Leaving each entity to define Emergency may lead to ambiguity with enforcement later. It would be better to address the issue now - either in the standard (perhaps by expressly allowing entities to define the scope of the term) or by redefining the term to include some measure of significance.
NIPSCO	No	EOP-011-1 covers the long-term planning horizon and we are not quite sure why, looking at the criteria. Please clarify. How does the "Operating Plan" required under EOP-011-1 R1 for mitigating operating emergencies in the TOP area mesh with the Operating Plan required under the new TOP-002-4 R2 and the one that has to be implemented under TOP-001-3 R14? Are these Operating Plans one in the same? If so, then the requirement EOP-011-1 R1 is redundant and should be deleted as this creates confusion. The Operating Plan for EOP-011-1 R1 requires RC review, but the Operating Plan mentioned in TOP-002 does not. This is not clear and should be addressed.Thanks
ReliabilityFirst	No	ReliabilityFirst votes in the Negative due to the non-enforceable language in R1 and R2 and offers the following comments for consideration:1. Requirement R1 and R2 - ReliabilityFirst appreciates the SDT removing the “Reliability Coordinator-approved” language but still questions “Reliability Coordinator-reviewed” language. In the scenario where the Reliability Coordinator does not review the Operating Plan, is the Transmission Owner (R1) or Balancing Authority (R2) non-compliant? Furthermore, there is no corresponding requirement for the TO or BA to supply the Operating Plan

Organization	Yes or No	Question 1 Comment
		to the Reliability Coordinator. To address both of ReliabilityFirst's concerns, ReliabilityFirst suggest the following language: "Each Transmission Operator shall develop, maintain, and implement an Operating Plan to mitigate operating Emergencies in its Transmission Operator Area [and make available to the Reliability Coordinator for review]. The Operating Plan shall include the following, as applicable:" 2. Requirement R3 Part 3.1.3 - In order for consistency between R3 and R4 regarding the Reliability Coordinator specifying a time period for the TOP or BA to address identified reliability risks, ReliabilityFirst recommends modifying R3 Part 3.1.3 to state; "Notify each Balancing Authority and Transmission Operator of the results [and time period for resubmittal if reliability risks are identified]."
We Energies	No	R1 and R2: The use of the term [implement] in the opening sentences of R1 and R2 should be removed and replaced with an additional sentence; the BA/TOP [shall act in accordance with their plan to mitigate a Capacity Emergency or Energy Emergency.]. The word implement can be interpreted to create a pre-emergency obligation (to train or provide other evidence of awareness) relative to the developed and maintained Operating Plan. To an extent, the measures for R1 and R2 address this issue with the phrase, [for times when an Emergency has occurred]. However, replacing implement with shall act in accordance with adds clarity to the requirement. R1.2.5 and R2.2.8: The requirements include language to [minimize] overlap of manual and automatic load shed and require that manual load shed be capable of being implemented in a [timeframe adequate for mitigating the Emergency.] This language creates requirements that are ambiguous and would be difficult to both audit and prove compliance. Additionally, the SDT's goal of keeping manual and automatic Load shed schemes as separate as possible does not fully consider the interaction between a TOP's UVLS and a BA's UFLS schemes. A BA maintaining separation between their manual load shed and UFLS, may have manual load shed plans that remove a TOP's UVLS. Additionally, the objective of a BA using

Organization	Yes or No	Question 1 Comment
		manual load shed to respond to Energy Emergencies and Capacity Emergencies is to balance the BA. UFLS under non-islanded conditions has a broader purpose of maintaining the entire Interconnection.R2.2.8: This requirement combines the Balancing Authority functional model role and the implementation of operator controlled manual Load shedding, which aligns with the DP role. The requirement is written assuming a vertically integrated utility with both BA and DP roles. When considering the functional model, a BA would affect manual load shed through the use of an Operating Instruction to a DP to shed the load. A non-vertically integrated BA does not have the means to directly affect load shed without an Operating Instruction.R3. The requirement does not identify a periodicity or requirements for ongoing RC review of Operating Plans, nor does it address timing of Operating Plan submittal to the RC. As the requirement is written, the first TOP or BA to submit a plan will receive the results of the RC review within 30 days. It is not clear to whom will the RC compare initially submitted plan if all the BA's or TOPs do not submit their plans at the same time. Alternately, if all BA / TOP plans are submitted to the RC at the same time, how effective will an RC review be if they are required complete their review within 30 calendar days? EOP 005-2 contains a well thought out process for periodicity and timing of submitting plans to an RC and should be considered as a template for this requirement.R4. As written, the requirement does not establish a set timeframe for the BA/TOP to address reliability risks identified during the RC review of the Operating Plans. R5: The phrase [and neighboring Reliability Coordinators] should be replaced with [and adjacent Reliability Coordinators.] This would be consistent with the notification process in Attachment 1, which requires the RC to [also notify all adjacent Reliability Coordinators.]
Salt River Project	No	SRP appreciated the efforts at revising the requirement for the Operating Plan to be approved by the Reliability Coordinator to just require reviewal

Organization	Yes or No	Question 1 Comment
		of the Operating Plan. However, there is no time frame or periodicity mentioned for when the Operating Plan should be reviewed. Please address when the Operating Plan needs to be reviewed.
Manitoba Hydro	No	Requirement R4 - the requirement that each Transmission Operator and Balancing Authority shall "address" any reliability risks... should berevised to state that each Transmission Operator and Balancing Authority shall "make a good faith attempt to address" any reliability risks identified by its Reliability Coordinator pursuant to Requirment R3. Requirment R3.1.1 requires the Reliability Coordinator to review each submitted Operating Plan on the basis of compatability and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans.. This implies that a given Transmission Operator or Balancing Authority may need to negotiate a modified approach with other Transmission Operators or Balancing Authorities . Since one party cannot compel an agreement with another party, only god faith efforts can be made to resolve an incompatibility . There is no mechanism or criteria specified in R3 for the Reliability Coordinator to pick one plan over another if two or more operating plans are inconsistent.
Exelon Companies	No	Requirement 1 states theTransmission Operator shall develop, maintain and implement an Operating Plan that includes: Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency.We are concerned with the use of "minimizes" and "adequate timeframe". This is open to interpretaion by compliance audit staff.
Texas Reliability Entity	No	In Requirement R1, use of the term "Transmission Operator Area" appears to assume that generation supply physically located within a Transmission Operator's footprint is part of their "Transmission Operator Area." As

Organization	Yes or No	Question 1 Comment
		currently defined, “Transmission Operator Area” is the collection of Transmission assets that the Transmission Operator is responsible for operating. Using this definition in the requirement may create a reliability gap if a TOP determines that generation facilities are not included in the Transmission Operator Area because they don't meet the definition of Transmission. For example, in the ERCOT region some TOPs have argued that certain generation units are not in their Transmission Operator Area and therefore the TOP is not required to monitor those facilities. A TOP’s Operating Plan for mitigating operating Emergencies should include all applicable generation supply (per the FERC-approved definition of Emergency) to eliminate any potential reliability gaps. Accordingly, Texas RE offers several options to resolve this reliability gap concern: 1) Revise the current approved definition of “Transmission Operator Area” to add language that addresses the inclusion of any generation supply that may impact the Transmission Operator’s “Area.” Proposed revision: “The collection of Transmission Facilities over which the Transmission Operator is responsible for operating, as well as generation, distribution and loads that have power flowing into or from these Facilities.”2) Add the phrase “connected to the Transmission Operator Area” after any usage of the word “generation” within the requirements (Example: R 1.2.2 could be revised to “Cancellation or recall of outages of Transmission or generation connected to the Transmission Operator Area.3) Add technical guidance to clarify the entity functions that are considered part of a Transmission Operator Area.Option 1 is Texas RE’s preferred result, but at a minimum, Option 3 should be incorporated by the SDT.
Tri-State Generation and Transmission Association, Inc.	No	While TSGT agrees that the language in R3 is better the Standard Drafting Team has created a one sided requirement with R4. By not requiring justification or coordination from the RC to the BA/TOP when they feel they have identified a reliabililty risk within the entities Operating Plan. With these changes they have also removed responsibility from the RC to the

Organization	Yes or No	Question 1 Comment
		TOP/BA by not requiring the RC to officially approve the plan yet the TOP/BA must address the RC's feedback. TSGT suggests the SDT come up with language that promotes a cooperative effort between the TOP/BA and the RC.
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council	Yes	
Dominion	Yes	
MRO NERC Standards Review Forum	Yes	Thought the NSRF agrees with the re-write of EOP-011-1, please note the following discrepancy. Within R5, the word "impaced" has been removed but remains in the High and Severe VSL, and in Attachment 1, section 2.2, 3.2, 3.4.1 and 0.1. The NSRF recommends that "impacted" be re-inserted into R5 to provide clarity and inorder to be aligned with the remaining parts of the proposed Standard.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	Yes	For R5, Southern suggests revising the requirement to add clarity. Suggested wording: R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area within 30 minutes from the time of receiving the Emergency notification,. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
Bonneville Power Administration	Yes	
Idaho Power	Yes	
Tacoma Power	Yes	

Organization	Yes or No	Question 1 Comment
Hydro-Quebec TransEnergie	Yes	
South Carolina Electric & Gas	Yes	

2. **Attachment 1. Do you agree with the changes made to Attachment 1 of EOP-011-1? If not, please specifically identify those changes that you do not agree with, the basis for your disagreement, and your proposed revisions to the language at issue**

Summary Consideration: Thank you for your comments.

Arizona Public Service Company, Northeast Power Council and Hydro-Quebec commented on the bullet point "An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements" in the "Circumstances" of EEA 2. The EOP SDT's intent is that in an EEA 2, an energy deficient Balancing Authority is unable to meet all of its energy requirements, but has addressed that condition by utilizing Demand response and any other Load management procedures it may have access to. It is also making emergency purchases from other Balancing Authorities to help remedy its situation. In an EEA 2, the Balancing Authority is still able to serve and provide regulation for its remaining Load and maintain its minimum Contingency Reserves; thus, it should not be a burden to the Interconnection. The use of Contingency Reserve margin as a dividing line between an EEA 2 and EEA 3 means that in an EEA 2, a Balancing Authority has taken Load management actions – short of "Load shedding" – but can still balance and control for its remaining firm Load and meet its minimum Contingency Reserve requirements – but just barely. Once a Balancing Authority has to dip into its Contingency Reserve margin for Load service or for regulation (or has to shed Load for some other reason), it is in an EEA 3. At that point, it is likely to become a burden to the Interconnection; that determination would be made by the Reliability Coordinator, and not by an individual Balancing Authority. Additional clarification to the bullet point "An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements" in the "Circumstances" of EEA 2: the EOP SDT maintains that the current language provides a Balancing Authority flexibility in defining their "minimum" Contingency Reserves at or above their most severe single contingency (MSSC), as they see necessary to manage reliability within their Balancing Authority Area. The EOP SDT finds it important to maintain this flexibility for the varying needs of the Balancing Authorities s across Interconnections.

In addressing several comments received, the EOP SDT has revised Attachment 1 to replace "adjacent" with "neighboring." The EOP SDT believes that there is a reliability benefit to notifying other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators; such notification provides situational awareness for those entities.

Dominion, ACES Standards Collaborators and NYISO submitted comments pertaining to reevaluation and revision of SOLs and IROLs during an EEA 3. The EOP SDT has received industry stakeholder consensus with regard to this language and the drafted language will be retained. Section 3.3 only addresses re-evaluation of SOL/IROL under an EEA 3. There is no requirement to restore previous SOL/IROL while under an EEA 3. Under Section 3.4, SOL and IROL can be returned to its pre-Emergency SOLs or IROLs condition upon a termination of the alert level.

Southern Company's requested clarification around pre and post contingency firm Load shed actions during an EEA 3. The EOP SDT retains the language as drafted; an EEA 3 is, by definition, when "Firm Load interruption is imminent or in progress."

SPP and Duke Energy requested justification for the changing "Operating Reserves" to "Contingency Reserves." For clarity, and to responds to comments previously received from industry stakeholders, which revealed a wide range of interpretations as to the meaning of the existing language of EOP-002-3.1 with respect to shedding Load, the EOP SDT revised the drafted language from the term "Operating Reserves" to "Contingency Reserves" and moved "Contingency Reserves" to EEA 3 to define a circumstance for when an entity may be considering shedding Load, as well as to align EOP-011-1 with BAL-002-2.

SPP further provided language revisions to 3.2, 3.3 and 3.3.1 of Attachment 1. The EOP SDT appreciates your comments and suggestions but maintains the drafted language provides sufficient clarity and will retain the language as drafted.

SPP asks: "Does the SDT believe it is necessary to shed Load to maintain Contingency Reserves? If so, under what conditions?" The EOP SDT's response is: ***No***. To clarify, the EOP SDT is stating that it is preferable to use your Contingency Reserve margins to serve Load; and, when you do, you are at EEA Level 3. It is outside the scope of the EOP SDT to define how every Balancing Authority will respond to the EEA conditions. Each Balancing Authority would define how to respond to an EEA 3 condition within their plan(s).

An additional question raised by SPP is: "How does one determine the level of risk to the interconnection which would drive a Balancing Authority to shed Load?" The EOP SDT cannot know all of the triggering events for all scenarios. It would be the responsibility of the Reliability Coordinator and/or the Balancing Authority to make such determinations and direct the BA to take appropriate action.

Comments were received to clarify the number of EEA levels (three v. four). The EOP SDT retains the language drafted as three EEA levels. Alert 0 is normal operations, not an Emergency.

Duke Energy suggested language revision to A. General Responsibilities (1.) Initiation by Reliability Coordinator and (2) Notification in Attachment 1. The EOP SDT appreciates Duke Energy's suggested language revision, but retains the drafted language, as it provides sufficient clarity. The notification is only that an EEA has been declared. Requirements R1 and R2 specify notification of System conditions.

Texas RE submitted a request for clarification of EEA 2.1; and Duke Energy suggested removing RCIS for 2.1 and 2.2 of EEA 2, 3.4.1 of EEA 3, and 0.1 of EEA 0 to be consistent with the removal of RCIS in Section A, General Responsibilities. The EOP SDT notes that the RCIS is an industry-wide tool and a defined NERC Glossary term. The EOP SDT does not believe additional language suggested provides further clarity of EEA 2, 2.1.

Duke Energy commented to retain the LSE's ability to request that a Reliability Coordinator declare an EEA. The EOP SDT has received industry consensus that the LSE be removed from the standard.

Duke Energy commented on drafting of a white paper or guidance document for clarity of the actions to be taken at each EEA level. The EOP SDT maintains that Attachment 1 defines the actions to be taken and that the rationales within the Attachment provide sufficient clarity.

Duke Energy additionally suggested a language revision from “terminates” to “downgraded” in Section 3.2 of Attachment 1. The EOP SDT maintains that “terminate” is the correct term to be used and retains the drafted language of Attachment 1. Entities do not necessarily move from EEA 3 to EEA 2, an entity may move to an Alert 0 condition.

Duke Energy further suggests language revision to 3.4.1 of Attachment 1, that notification by a Balancing Authority has already been established as part of 3.4. The EOP SDT believes the drafted language is sufficient in clarity and the proposed modification does not add further clarity.

ACES Standards Collaborators requested clarification of Section 3.3, would it be inconsistent with FAC-014 and FAC-011. The EOP SDT does not view Section 3.3. as an inconsistency with the stated FAC standards; EOP-011-1 addresses Emergencies; whereas the FAC standards address establishment of SOLs and IROLs.

ACES Standards Collaborators requested clarification as to the Balancing Authority and its communications with other Balancing Authorities in an EEA 2. The Balancing Authority is fully aware of its contracts with other Balancing Authorities and market participants. This communication is more efficient than using the Reliability Coordinator.

SRC noted that 2.3 of Attachment 1 is redundant to requirements in IRO-014-3. Attachment 1 is not imposing an additional requirement. IRO-014-3 limits the notification to “other impacted” Reliability Coordinators. The EOP SDT believes that there is a reliability benefit to notifying other Balancing Authorities and Transmission Operators in it Reliability Coordinator Area and neighboring Reliability Coordinators; such notification provides situational awareness for those entities.

NYISO suggested a language revision in Section 2.4 of Attachment 1 to “…in order to mitigate the emergency.” The EOP SDT retains the drafted language of the Attachment. The proposed revision does not add further clarity to Section 2.4.

NYISO requested clarity of Section 2.5.1 of Attachment 1, specifically if this includes quick start units used to maintain Contingency Reserve while offline. The intent of the EOP SDT is that under EEA 2 conditions, *all* units not being held in to meet minimum Contingency Reserve requirements should be online and capable of producing power prior to moving to an EEA 3. When an EEA is terminated, an entity is in normal operations and covering Load and Operating Reserves.

Texas RE commented on responsibility element in EEA 3 and recommended language revision to add “Sharing information on resource availability” within the responsibilities. The EOP SDT maintains the drafted language of Attachment 1 provides sufficient clarity; Paragraph 3.1 states, “Continue actions from EEA 2.”

The EOP SDT made the following revisions to Attachment 1 of EOP-011-1 based on industry stakeholder comments/suggestions and clarification requests:

Rationale box for Introductions:

"EOP-002-3.1 Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request as permitted in its transmission tariff, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specifications did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ E-tag Specification v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired."

Sharing information on resource availability. Other ~~The~~ Reliability Coordinators of ~~a~~ Balancing ~~Authority~~ Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

Rationale box was added to EEA 3 and reads as:

Rationale for EEA 3:

This rationale *was added at the request of stakeholders asking for justification for moving a lack of Contingency Reserves into the EEA3 category.*

The previous language in EOP-002-3.1, EEA 2 used "Operating Reserve," which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently. Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using minimum Contingency Reserve in the language would eliminate some of the confusion. This is a different approach but the drafting team believes this is a good approach and was supported by several commenters.

Using Contingency Reserves (which is a subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that the point where a BA can no longer maintain this important Contingency Reserves margin is a most serious condition and puts the BA into a position where they are very close to shedding Load ("imminent or in progress"). The drafting team felt that this warrants categorization at the highest level of EEA.

The EOP SDT has made corrective revisions to suggested punctuation, grammar and syntax in EOP-011-1 where merited.

Organization	Yes or No	Question 2 Comment
Arizona Public Service Company	No	We appreciate that the SDT addressed our comments regarding the need for definitive triggers between the EEA levels. However, with the inclusion of the final bullet of the circumstances section on EEA 2, AZPS believes that as written, the Circumstances together, where an entity is energy deficient and still maintaining their reserves at the same time, would be inappropriately burdening the interconnection. Is this the intent of the change?, If not, additional clarification around the Circumstances is requested.
Northeast Power Coordinating Council	No	In EEA 2, a bullet was added addressing the ability of the BA to maintain “minimum Contingency Reserve requirements”. This could be interpreted in two ways because of the use of the word “minimum”. It should be revised to avoid any misinterpretation. The first interpretation is that the BA would declare an EEA level 2 event though the contingency reserve requirement, equal to the BA’s Most Severe Single Contingency as defined in BAL-002-1, Part 3.1, is fully met. If this is the SDT’s intent, then suggest the following language: “An energy deficient Balancing Authority is still able to maintain Contingency Reserve requirement.”The second interpretation is that in EEA level 2, depletion of Contingency Reserve is allowed, however some minimum level(s) can still be maintained. These minimum levels are defined by local procedures and may be different from one BA to the other, based on local constraints. If this is the SDT’s intent, we then suggest the following language: “An energy deficient Balancing Authority is still able to maintain a minimum level of Contingency Reserve while Contingency Reserve may be depleted.”For example, an entity has a Contingency Reserve requirement equal to its MSSC, which is normally 1000 MW. However, there is a minimum level of 250 MW that could be maintained in all cases in order to provide minimum levels of regulation and frequency responsive reserve. In this case, the second interpretation is the right one.

Organization	Yes or No	Question 2 Comment
Dominion	No	Suggest revising Notification so that it is consistent with the standard. The standard uses 'neighboring RCs' whereas the attachment uses "adjacent RCs". Under EEA, at 2.4 - Dominion believes this occurs only where a SOL or IROL is restricting the deficient Balancing Authority's ability to import energy necessary to mitigate its Capacity Emergencies and Energy Emergencies. If so, suggest SDT consider explicitly stating this.
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	Southern understands the SDT's approach in the revised Attachment 1, but we think there is still sufficient confusion in the industry around pre and post contingency firm load shed actions during an EEA 3. We request that the SDT provide some clarity around these actions in the Attachment 1 as suggested below but at a minimum in the consideration of comments, whitepaper, or some other form. Based on the current draft, if an entity experiences a situation where its Contingency Reserves fall below the minimum, the entity would be in an EEA3. Just because an entity's Contingency Reserves have fallen below the minimum should not mean, however, that firm load shed is required pre-contingency in order to restore the minimum generation-side contingency reserves. Southern recommends that the "Circumstances" for EEA3 be revised to the following:The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements AND foresees the use of firm load shed to respond post-contingency to a generation contingency event or to recover generation/load balance pre-contingency.
PPL NERC Registered Affiliates	No	Attachment A, section B.2.1 - This section is preceded by the sentence, "During an EEA 2, RCs and BAs have the following responsibilities," yet this section also includes responsibilities of market participants. What obligation do the market participants (PSEs) have to proactively look for communications from requesting BAs? Market participants (PSEs) may not have access to the RCIS website. Due to the ambiguity of the market participant responsibilities in the attachment and the fact that there are no requirements of "market participants" within the standard, PPL Companies recommend that the market participant responsibilities be removed from the

Organization	Yes or No	Question 2 Comment
		attachment entirely. Attachment A, section B.2.1 - This section states that, “the requesting BA shall communicate its needs to other BAs and market participants,” but it does not describe how the BA is to make this communication. It appears this is a real time communication between the requesting BA and market participants (PSEs) but it is not clear over what medium and timeframe the communication is to occur. Attachment A, section B.2.5.1 - The mention of “all available generation units” is unnecessary as this is previously mentioned as a circumstance of an EEA1 in section B.1.
Associated Electric Cooperative, Inc.	No	AECI agrees with SPP Comments
SPP Standards Review Group	No	Introduction - In what appears to be the rationale for the introduction, insert the phrase ‘as permitted in its transmission tariff’ following ‘request’ in the 2nd line of the paragraph.General Responsibilities/Notification - Notification is to go out to all ‘adjacent’ Reliability Coordinators. As pointed out in Question 1 above, the term used in Requirement R5 is ‘neighboring’. Neither term is really needed since Section 2.1 requires notification via the RCIS which will automatically notify all Reliability Coordinators. We suggest deleting the terms ‘adjacent’ and ‘neighboring’.EEA Levels - Throughout the remainder of Attachment 1, an extra space pops up between ‘Reliability Coordinator’ and ‘s’ in Reliability Coordinators. The introduction section here refers to three EEA levels yet there are four identified. Either change this back to four or delete Alert 0.EEA 2 - In the paragraph immediately above 2.1, delete the extra ‘s’ after Balancing Authorities.2.3 - We suggest rewording the beginning of this sentence to ‘Other Reliability Coordinators of Balancing Authorities with available resources…’. Otherwise a Reliability Coordinator is required to communicate with itself.2.4 - Insert ‘to-service’ between ‘return’ and ‘any’ in the 3rd line.Rationale for EEA 2-Capitalize Contingency Reserves.EEA 3 - Under Circumstances it states that a Balancing Authority that is unable to sustain minimum Contingency Reserve requirements must be in an EEA 3. We appreciate the SDT’s effort to clarify this position. Traditionally, lack of Operating Reserves has been associated with EEA 2.

Organization	Yes or No	Question 2 Comment
		The SDT has chosen to split Contingency Reserves out and hold them as a qualifier for EEA 3 which has traditionally been associated with actual or immenient Load shedding. Such a move will increase the number of EEA 3s which could be taken as an indication of a degradation of reliability. What is the SDT's justification for making such a significant change? What are the drivers forcing this modification? In response to a question submitted via the Chat feature during the webinar, the SDT provided the following response: 'First, The previous language used "Operating Reserve," which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently and have a defined minimum value (MSSC or as defined by Reserve Sharing Group). Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using Contingency Reserve in the language would eliminate some of the confusion. Yes, this is a different approach but the Drafting Team believes this is a good approach and was supported by several commenters. Second, Using Contingency Reserve (which is subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that this point where a BA can no longer maintain this important Contingency Reserve margin is a most serious condition and puts the BA into a position where they are very close to shedding Load ("imminent or in progress"). The drafting team felt that this warrants categorization at the highest level of EEA.Finally, there is an issue concerning the move toward establishing an exemption from BAL-002 compliance when a BA is suffering an energy related emergency. Given the importance of Contingency Reserve margins, this exemption cannot be taken lightly. The drafting team believes that it is allowable to use the Contingency Reserve margin in an Emergency, but that should be the very last resort. For these reasons, the Drafting Team defined the condition where your Contingency Reserve resources, being for regulation or to serve your Load, at the highest level of Alert.' We certainly appreciate the response but believe the SDT needs to post this justification in a rationale box associated with the EEA 3 Level. That

Organization	Yes or No	Question 2 Comment
		will help alleviate any misunderstanding which may exist as well as provide a permanent record of why the change was made.3.2 - We suggest rewording the last three lines of this section to read '...Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur informing other Reliability Coordinators in the process and pass this information on to impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area.'3.3/3.3.1 - We suggest the following changes in the last four lines of 3.3 and incorporate 3.3.1 into 3.3: 'Transmission Operator whose Transmission Owner's equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Operator whose Transmission Owner's equipment is at risk. Before SOLs or IROLs are revised, the energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.We appreciate the SDT sharing its justification on including a lack of Contingency Reserves in EEA 3. However, this brings another question regarding when it is necessary to shed Load in order to maintain Contingency Reserves. Does the SDT believe it is necessary to shed Load to maintain Contingency Reserves? If so, under what conditions? In 3.3.1, a Balancing Authority is required to 'take whatever actions are necessary to mitigate any undue risk to the Interconnection'. This may include shedding Load. How does one determine the level of risk to the Interconnection which would drive a Balancing Authority to shed Load?3.4 - Either delete the 'the' in front of 'Systems' in the 2nd line or change 'Systems' to 'System'.3.4.1 - We suggest the following changes: 'Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the other Reliability Coordinators (via the RCIS) and the impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area that their Systems can be returned to normal limits.'
Duke Energy	No	(1)Duke Energy suggests the following revision to A.1. of Attachment 1:"1. Declaration by Reliability Coordinator. An Energy Emergency Alert (EEA) may be

Organization	Yes or No	Question 2 Comment
		declared only by a Reliability Coordinator at 1) the Reliability Coordinator's own discretion, or 2) upon the request of the Balancing Authority or Load Serving Entity." We still believe that at a minimum, EOP-011 should retain the LSE's ability to request that an RC declare an EEA. Though EOP-011 and Attachment 1 may not have to be prescriptive in the activities expected of LSEs during an energy emergency, we believe that the responsibility of LSEs to procure additional resources as needed to address real-time deficiencies needs to be clearly understood and not be inadvertently moved to the Host BA by the changes proposed. In addition, LSEs who are not part of ISO/RTO markets should still have the ability to notify the RC or BA when they are experiencing an energy emergency. Finally, we believe that the RC is responsible for declaring an EEA and the associated notifications. The BA or LSE is responsible for initiating the EEA through the notification to the RC.(2)Duke Energy suggests the following revision to A.2. of Attachment 1:"Notification. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all adjacent Reliability Coordinators of system conditions."We believe the added language provides additional clarity.(3)Duke Energy suggests removing RCIS for 2.1 and 2.2 of EEA 2, 3.4.1 of EEA 3, and 0.1 of EEA 0 to be consistent with the removal of RCIS in Section A, General Responsibilities.(4)Duke Energy believes that a white paper or guidance document is needed to clarify the necessary actions taken at each EEA level. As written, it is difficult to identify those actions and a white paper or guidance document would be beneficial.(5)There appear to be typos within the attachment and suggest replacing "Reliability Coordinator s" with "Reliability Coordinator's "(6) Duke Energy suggests replacing "terminates" with "downgraded" in section 3.2 of Attachment 1. We believe this change better clarifies the SDT's intent and is also consistent with the language in 3.4.1. (7) Duke Energy suggests replacing "requirements" with "actions" in section 3.3 of Attachment 1. We believe this change better clarifies the SDT's intent.(8)Duke energy suggests the following revision to 3.4.1 of Attachment 1:"Notification of other parties. Upon downgrading the alert by the Reliability Coordinator, the Reliability Coordinator shall notify the

Organization	Yes or No	Question 2 Comment
		impacted Reliability Coordinator's, Balancing Authorities and Transmission Operators that its Systems can be returned to its normal limits."We believe that the notification piece by a BA has already been established as part of 3.4 and is not necessary in 3.4.1.(9)Duke Energy suggests replacing "Operating Reserves" with "Contingency Reserves" to be consistent with maintaining Contingency Reserves as outlined in Attachment 1. If the SDT believes that Operating Reserve is the appropriate term, can the SDT explain the rationale behind using Operating Reserve instead of Contingency Reserve?
ACES Standards Collaborators	No	(1) We question the re-evaluation and revision of SOLs and IROLs during an EEA 3. First, this step should be completed prior to entering EEA3 because load shed is already occurring or is imminent. We understand that there is a step 2.4 under EEA 2 that considers that impact of Transmission outages on IROLs and SOLs but it does not call for re-evaluation or revising of IROLs and SOLs even if Transmission Elements are returned to service. By the time the situation reaches EEA 3, load shedding is occurring. If there are activities, such as reevaluating SOLs (e.g. using a shorter duration emergency limit) to prevent load shedding, the re-evaluation should occur during should be done during EEA 2 with implementation of the new limit in EEA 3. (2) We believe section 3.3.1 and the last sentence of 3.3 should be struck as they are ambiguous and cause confusion. First, section 3.3.1 appears to limit use of revised SOLs and IROLs until after load shed occurs. The bottom line is revised IROLs and SOLs should be used to prevent load shed not mitigate it once it has occurred. The RC can revise IROLs at any and the TOP can revise SOLs at anytime as long as they are consistent with the RC's SOLs methodology. (3) Section 3.3 is inconsistent with FAC-014 and FAC-011. FAC-014 requires the RC to establish an SOL methodology and FAC-011 requires the RC to establish IROLs and the TOP to establish SOLs consistent with the methodology. The RC does not require TOP agreement to modify IROLs as they have the authority to establish an IROL. The only real issue here is that the RC and TOP need to make sure they are not violating the TOP's Facility Ratings established per their Facility Ratings methodology (FAC-008). FAC-011 R1.2 already requires this. We suggest simply stating that "Reevaluation of SOLs and IROLs shall

Organization	Yes or No	Question 2 Comment
		be coordinated with other Reliability Coordinators and Transmission Operators consistent with the RC's SOL Methodology and TO's Facility Ratings Methodology." (4) We question why a BA has to communicate its needs to other BAs in EEA2. They should only be required to notify its RC who then communicates the issue via RCIS which will notify all BAs at the same time. This avoids the compliance issue of whether the RC notification per the RCIS satisfies the BA's obligation. (5) There are several extraneous "s" in the attachment usually after Reliability Coordinator or Balancing Authority. Look at the last sentence of EEA2 for example.
Peak Reliability	No	The notification section should have "impacted" or "affected" or "as applicable" language in it so the RC doesn't have to notify ALL BAs/TOPs and adjacent RCs for all emergencies - just those that need to know such information.
ISO/RTO Council Standards Review Committee (SRC)	No	1. The SRC notes that Subsection 2.3 is redundant with the requirements contained in IRO-014-3. To avoid duplication, it is recommended that this subsection be removed.2. The SRC notes two minor typographical errors: a. Sections B and subsections 2.2, 3, 3.1, 3.3, and 0.1 appear to contain an inadvertent space in the added term "Reliability Coordinator s". This space should be removed.b. The third sentence in Section B is not part of a requirement and is, therefore, unnecessary and should be removed.c. It is recommended that the circumstances underlying an EEA 2 be clarified. The following revisions are proposed:Circumstances: o The Balancing Authority is an energy deficient Balancing Authority ando Is no longer able to meet energy requirements. o Has implemented its Operating Plan to mitigate Emergencies. o Is still able to maintain minimum Contingency Reserve requirements. d. Section 3.3.1 appears to contain an inadvertent word "it" before "will immediately take..." This should be removed from Section 3.3.1.
Kansas City Power and Light	No	Introduction - In what appears to be the rationale for the introduction, insert the phrase 'as permitted in its transmission tariff' following 'request' in the 2nd line of the paragraph.General Responsibilities/Notification - Notification is to go out to all 'adjacent' Reliability Coordinators. As pointed out in Question 1 above, the term used

Organization	Yes or No	Question 2 Comment
		in Requirement R5 is 'neighboring'. Neither term is really needed since Section 2.1 requires notification via the RCIS which will automatically notify all Reliability Coordinators. We suggest deleting the terms 'adjacent' and 'neighboring'.EEA Levels - Throughout the remainder of Attachment 1, an extra space pops up between 'Reliability Coordinator' and 's' in Reliability Coordinators. The introduction section here refers to three EEA levels yet there are four identified. Either change this back to four or delete Alert 0.EEA 2 - In the paragraph immediately above 2.1, delete the extra 's' after Balancing Authorities.2.3 - We suggest rewording the beginning of this sentence to 'Other Reliability Coordinators of Balancing Authorities with available resources...'. Otherwise a Reliability Coordinator is required to communicate with itself.2.4 - Insert 'to-service' between 'return' and 'any' in the 3rd line.Rationale for EEA 2-Capitalize Contingency Reserves.EEA 3 - Under Circumstances it states that a Balancing Authority that is unable to sustain minimum Contingency Reserve requirements must be in an EEA 3. We appreciate the SDT's effort to clarify this position. Traditionally, lack of Operating Reserves has been associated with EEA 2. The SDT has chosen to split Contingency Reserves out and hold them as a qualifier for EEA 3 which has traditionally been associated with actual or immenient Load shedding. Such a move will increase the number of EEA 3s which could be taken as an indication of a degradation of reliability. What is the SDT's justification for making such a significant change? What are the drivers forcing this modification? In response to a question submitted via the Chat feature during the webinar, the SDT provided the following response: 'First, The previous language used "Operating Reserve," which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently and have a defined minimum value (MSSC or as defined by Reserve Sharing Group). Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using Contingency Reserve in the language would eliminate some of the confusion. Yes, this is a different approach but the Drafting

Organization	Yes or No	Question 2 Comment
		Team believes this is a good approach and was supported by several commenters. Second, Using Contingency Reserve (which is subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that this point where a BA can no longer maintain this important Contingency Reserve margin is a most serious condition and puts the BA into a position where they are very close to shedding Load ("imminent or in progress"). The drafting team felt that this warrants categorization at the highest level of EEA.Finally, there is an issue concerning the move toward establishing an exemption from BAL-002 compliance when a BA is suffering an energy related emergency. Given the importance of Contingency Reserve margins, this exemption cannot be taken lightly. The drafting team believes that it is allowable to use the Contingency Reserve margin in an Emergency, but that should be the very last resort. For these reasons, the Drafting Team defined the condition where your Contingency Reserve resources, being for regulation or to serve your Load, at the highest level of Alert.' We certainly appreciate the response but believe the SDT needs to post this justification in a rationale box associated with the EEA 3 Level. That will help alleviate any misunderstanding which may exist.3.2 - We suggest rewording the last three lines of this section to read '...Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur informing other Reliability Coordinators in the process and pass this information on to impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area.'3.3/3.3.1 - We suggest the following changes in the last four lines of 3.3 and incorporate 3.3.1 into 3.3: 'Transmission Operator whose Transmission Owner's equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Operator whose Transmission Owner's equipment is at risk. Before SOLs or IROLs are revised, the energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.We appreciate the SDT sharing its justification on including a lack of Contingency Reserves in EEA 3. However, this brings another question regarding when it is

Organization	Yes or No	Question 2 Comment
		necessary to shed Load in order to maintain Contingency Reserves. Does the SDT believe it is necessary to shed Load to maintain Contingency Reserves? If so, under what conditions? In 3.3.1, a Balancing Authority is required to 'take whatever actions are necessary to mitigate any undue risk to the Interconnection'. This may include shedding Load. How does one determine the level of risk to the Interconnection which would drive a Balancing Authority to shed Load?3.4 - Either delete the 'the' in front of 'Systems' in the 2nd line or change 'Systems' to 'System'.3.4.1 - We suggest the following changes: 'Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the other Reliability Coordinators (via the RCIS) and the impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area that their Systems can be returned to normal limits.'
Hydro-Quebec TransEnergie	No	In EEA 2, a bullet was added addressing the ability of the BA to maintain "minimum Contingency Reserve requirements". This could be interpreted in two ways because of the use of the word "minimum". It should be revised to avoid any misinterpretation. The first interpretation is that the BA would declare an EEA level 2 event though the contingency reserve requirement, equal to the BA's Most Severe Single Contingency as defined in BAL-002-1, Part 3.1, is fully met. If this is the SDT's intent, then suggest the following language: "An energy deficient Balancing Authority is still able to maintain Contingency Reserve requirement."The second interpretation is that in EEA level 2, depletion of Contingency Reserve is allowed, however some minimum level(s) can still be maintained. These minimum levels are defined by local procedures and may be different from one BA to the other, based on local constraints. If this is the SDT's intent, we then suggest the following language: "An energy deficient Balancing Authority is still able to maintain a minimum level of Contingency Reserve while Contingency Reserve may be depleted."For example, an entity has a Contingency Reserve requirement equal to its MSSC, which is normally 1000 MW. However, there is a minimum level of 250 MW that could be maintained

Organization	Yes or No	Question 2 Comment
		in all cases in order to provide minimum levels of regulation and frequency responsive reserve. In this case, the second interpretation is the right one.
New York Independent System Operator	No	The NYISO proposes the following additions:Section 2.4 should include the phrase: ".. in order to mitigate the energy emergency. "Section 2.5.1 requires all generators to be on-line. The NYISO would like to clarify that this does not include quick start units (e.g., 10 minute GT resources) used to maintain contingency reserve while off-line?Section 3.3 indicates that revised SOL/IROLs would only be revised as long as the EEA 3 condition exists. The NYISO is unclear on what conditions related to an EEA 3 would require an entity to restore previous SOL/IROL's. If a new SOL/IROL was developed would that not be valid for the existing conditions?
Texas Reliability Entity	No	1) Attachment 1 contains terms that are not consistent with the language in the requirements. The following comments identify the areas of inconsistency: Section A, Item 2: Attachment 1, Section A. General Responsibilities, Item 2. Notification, last sentence uses the term adjacent RCs. Based on the Rationale for (2) Notification, it appears that the use of the term “adjacent” is aligned with IRO-014-3, Requirement R1 which uses the term. However, EOP-001-1 Requirement R5 uses the term neighboring RCs. Texas RE recommends the term “adjacent” be replaced with “neighboring” in Section A, Item 2. Section B. EEA Levels, 2. EEA 2, 2.2 Declaration Period, last sentence uses the term “impacted” RCs, BAs and TOPs. However, Requirement R5 replaced the term “impacted” with “neighboring.” Texas RE recommends the term “impacted” be replaced with “neighboring.” Section B. EEA Levels, 3. EEA 3, 3.2 Declaration Period, last sentence uses the term “impacted” RCs, BAs and TOPs. However, Requirement R5 replaced the term “impacted” with “neighboring.” Texas RE recommends the term “impacted” be replaced with “neighboring.” Section B. EEA Levels, 3. EEA 3, 3.4.1 Notification of other parties uses the term “impacted” RCs, BAs and TOPs. However, Requirement R5 replaced the term “impacted” with “neighboring.” Texas RE recommends the term “impacted” be replaced with “neighboring.” Section B. EEA Levels, Alert 0 - Termination, 0.1 Notification uses the term impacted RCs, BAs and TOPs. However, Requirement R5

Organization	Yes or No	Question 2 Comment
		replaced the term “impacted” with “neighboring.” Texas RE recommends the term “impacted” be replaced with “neighboring.” 2) Section B, EEA Levels, 2. EEA 2, 2.1, Texas RE suggests the addition of clarifiying language to more clearly indicate the RC responsibility as follows: “Upon request [of an EEA] from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.” 3) Section B, EEA Levels, 2. EEA 2, 2.4 Texas RE suggests that “Transmission Operator” should be “Transmission Operator(s).” 4) Section B, EEA Levels, 3. EEA 3, Texas RE suggests there is a responsibility missing from the EEA Level 3 list and recommends adding the responsibility of “Sharing information on resource availability” (as listed within EEA Level 2) within EEA Level 3 responsibilities.
MRO NERC Standards Review Forum	Yes	Please see question 1.
Tennessee Valley Authority	Yes	
FirstEnergycorp	Yes	FIRSTENERGY supports the RSC comments which are reflected below but was not provided as an option before the ballots.We agree with all the changes. Just a typo: the word “it” before “will immediately take...” should be removed from Section 3.3.1.
DTE Electric	Yes	
Bonneville Power Administration	Yes	
Independent Electricity System Operator	Yes	We agree with all the changes. Just a typo: the word “it” before “will immediately take...” should be removed from Section 3.3.1.
Idaho Power	Yes	

Organization	Yes or No	Question 2 Comment
Tacoma Power	Yes	
We Energies	Yes	
Salt River Project	Yes	
Manitoba Hydro	Yes	
South Carolina Electric & Gas	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	

3. Violation Risk Factors (VRF) and Violation Severity Levels (VSL). The EOP SDT has made revisions to conform with changes to requirements and respond to stakeholder comments. Do you agree with the VRFs and VSLs for EOP-011-1? If you do not agree, please explain why and provide recommended changes

Summary Consideration: Thank you for your comments.

Dominion suggested removal of the term “impacted” from the Requirement R5 High/Severe VSL for consistency with the change made to Requirement R5. The EOP SDT agrees with this suggestion, and has made the revision.

Several commenters expressed concern regarding the High and Severe VSLs for Requirement R5, specifically regarding the time associated with the Requirements. The EOP SDT maintains that notifications under Emergency conditions are imperative and that violation of this requirement merits a High VSL.

SPP Standards Review Group suggested language changes for the Moderate and High VSLs for consistency with the Requirement and other associated documents. The EOP SDT revised the language as appropriate. SPP also recommended language revisions to Requirement R4, however, the EOP SDT does not believe it is necessary to use “responsible entity.”

DTE Electric suggested revising the VSLs associated with R3 to conform to the requirement language. The EOP SDT agrees with the suggestion and has revised the language as appropriate.

ACES Standards Collaborators suggested adding a Lower VSL table for Requirement R1 as well as adding a Lower and Moderate VSL for Requirement R4. The EOP SDT believes that the VSLs are appropriate as written. Also, ACES Standards Collaborators, along with Texas Reliability Entity, suggested revising the language used in the Severe VSL for Requirement R5 to conform with the language used in Requirement R5. The EOP SDT revised the language as per Requirement R5 which uses the term “neighboring.”

Exelon Companies expressed concern that the VSLs for Requirement R1 do not refer to particular Parts of the Requirement. The EOP SDT believes that the VSLs are appropriate as written. The use of “as applicable” in the requirement precludes the use of subparts in the VSL.

Organization	Yes or No	Question 3 Comment
Dominion	No	R5 High/Severe VSL have ‘notify impacted RCs’, the word impacted needs to be removed as it was removed in R5 and the VLS needs to be updated to match R5.

Organization	Yes or No	Question 3 Comment
FirstEnergycorp	No	FIRSTENERGY supports the RSC comments which are reflected below but was not provided as an option before the ballots.We agree with most of the assigned VRFs and VSLs, but have a concern over the lack of clear demarcation between the HIGH and SEVERE VSLs for R5.In brief, a HIGH VSL is assigned when the RC notifies others but not within the 30 minute target; whereas the RC is assigned a SEVERE VSL if it failed to notify others. It is unclear as to what time period an RC is assessed “failed to notify”. Is it 1 hour, 2 hours or 24 hours after the declaration of Emergency? The longer the period, e.g., 24 hours, the more meaningless will the HIGH VSL become since an RC may notify others 4 or 5 hours after the declaration but by that time, the Emergency may have been resolved or worsened to the point whe some cascading has occurred. We therefore suggest the SDT consider making the VSLs for R5 a fully staggered one: with a LOWER, MEDIUM, HIGH and SEVERE starting with, for example, the LOWER VSL being up to 5 minutes late in notifying others, MEDIUM VSL being up to 10 minutes late, HIGH being up to 15 minutes late and SEVERE being more than 15 minutes late (or never). The SDT may want to apply other time frames as it sees appropriate.
SPP Standards Review Group	No	R1 - Change the Moderate VSL to state ‘...to mitigate operating Emergencies in its Transmission Operator Area...’ to be consistent with the requirement and the other VSLs for this requirement. Change ‘...the Reliability Coordinator.’ in the High VSL to ‘...its Reliability Coordinator.’R2 - Add the phrase ‘within its Balancing Authority Area’ following the usage of ‘Emergencies’ in the Moderate, High and Severe VSLs for Requirement R2.R3- Insert ‘-calendar’ following ‘30’ in the High VSL.R4 - Replace ‘Transmission Operator and Balancing Authority’ with ‘responsible entity’ in the High and Severe VSLs for Requirement R4. Also, replace ‘the’ with ‘its’ when referring to the Operating Plan or Reliability Coordinator.R5 - We suggest rewording the High and Severe VSLs to read: High - The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area, did notify impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area and other Reliability Coordinators

Organization	Yes or No	Question 3 Comment
		but did not notify them within 30 minutes from the time of receiving notification. Severe - The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area, failed to notify impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area and other Reliability Coordinators.
DTE Electric	No	Comments: For R3 High VSL, the requirement as written does not specify notification within 90 days. Our suggested revision to R3 in response to question 1 corrects this issue.
ACES Standards Collaborators	No	(1) We recommend adding a Lower VSL table for Requirement R1. There may be several factors, such as late annual reviews (one to three months late) that could result in a lower VSL. (2) For Requirement R4, we recommend adding a Lower and Moderate VSL. Failing to make updates by the RC deadline by a short time (one to thirty days) could be a Lower or Moderate VSL.(3) For Requirement R5, the Severe VSL requires notification of “impacted” RCs, BAs, and TOPs but the requirement states “adjacent” RCs, BAs, and TOPs. Which entities are required to be notified, impacted or adjacent?
ISO/RTO Council Standards Review Committee (SRC)	No	The SRC has the following concerns regarding the VSLs/VRFs:a. The SRC agrees with most of the assigned VRFs and VSLs, but have the following concerns:i. The VRF for Requirement R3 should be medium as it is an administrative requirement.b. There lacks a clear demarcation between the HIGH and SEVERE VSLs for Requirement R5. In brief, a HIGH VSL is assigned when the RC notifies others but not within the 30 minute target; whereas the RC is assigned a SEVERE VSL if it failed to notify others. It is unclear as to what time period an RC is assessed “failed to notify”. Is it 1 hour, 2 hours or 24 hours after the declaration of Emergency? Clarification is needed. Accordingly, the SRC suggests that the SDT consider making the VSLs for R5 fully staggered, which would include LOWER, MEDIUM, HIGH and SEVERE VSLs. For example, the LOWER VSL being up to 10 minutes late in notifying others, MEDIUM

Organization	Yes or No	Question 3 Comment
		VSL being up to 20 minutes late, HIGH being up to 30 minutes late and SEVERE being more than 30 minutes late.
Independent Electricity System Operator	No	We agree with most of the assigned VRFs and VSLs, but have a concern over the lack of clear demarcation between the HIGH and SEVERE VSLs for R5.In brief, a HIGH VSL is assigned when the RC notifies others but not within the 30 minute target; whereas the RC is assigned a SEVERE VSL if it failed to notify others. It is unclear as to what time period an RC is assessed “failed to notify”. Is it 1 hour, 2 hours or 24 hours after the declaration of Emergency? The longer the period, e.g., 24 hours, the more meaningless will the HIGH VSL become since an RC may notify others 4 or 5 hours after the declaration but by that time, the Emergency may have been resolved or worsened to the point whe some cascading has occurred. We therefore suggest the SDT consider making the VSLs for R5 a fully staggered one: with a LOWER, MEDIUM, HIGH and SEVERE starting with, for example, the LOWER VSL being up to 5 minutes late in notifying others, MEDIUM VSL being up to 10 minutes late, HIGH being up to 15 minutes late and SEVERE being more than 15 minutes late (or never). The SDT may want to apply other time frames as it sees appropriate.
Kansas City Power and Light	No	R1 - Change the Moderate VSL to state ‘...to mitigate operating Emergencies in its Transmission Operator Area...’ to be consistent with the requirement and the other VSLs for this requirement. Change ‘...the Reliability Coordinator.’ in the High VSL to ‘...its Reliability Coordinator.’R2 - Add the phrase ‘within its Balancing Authority Area’ following the usage of ‘Emergencies’ in the Moderate, High and Severe VSLs for Requirement R2.R3- Insert ‘-calendar’ following ‘30’ in the High VSL.R4 - Replace ‘Transmission Operator and Balancing Authority’ with ‘responsible entity’ in the High and Severe VSLs for Requirement R4. Also, replace ‘the’ with ‘its’ when referring to the Operating Plan or Reliability Coordinator.R5 - We suggest rewording the High and Severe VSLs to read: High - The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority within it Reliability Coordinator Area, did notify impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area and other Reliability Coordinators

Organization	Yes or No	Question 3 Comment
		but did not notify them within 30 minutes from the time of receiving notification. Severe - The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area, failed to notify impacted Balancing Authorities and Transmission Operators within its Reliability Coordinator Area and other Reliability Coordinators.
Exelon Companies	No	The VSL for R1 does not identify any of the sub requiirments in the standard, the VSL's lack specificity.
Texas Reliability Entity	No	Requirement R5 VSL language does not match the updated Requirement R5 language. Texas RE recommends that the VSL language be updated to reflect the revised R5 language. The term “impacted” should be removed and replaced with “neighboring.” The R5 VSL update would read as follows: “The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify other [impacted] Reliability Coordinators, Balancing Authorities and Transmission Operators [in its Reliability Coordinator Area, and neighboring Reliability Coordinators] but did not notify within 30 minutes from the time of receiving notification.”
Arizona Public Service Company	Yes	
Northeast Power Coordinating Council	Yes	
MRO NERC Standards Review Forum	Yes	Please see question 1.
Southern Company: Southern Company Services, Inc.; Alabama Power Company;	Yes	

Organization	Yes or No	Question 3 Comment
Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing		
Duke Energy	Yes	
Bonneville Power Administration	Yes	
Idaho Power	Yes	
Tacoma Power	Yes	
Hydro-Quebec TransEnergie	Yes	
We Energies	Yes	
Salt River Project	Yes	
Manitoba Hydro	Yes	
South Carolina Electric & Gas	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	

4. Are there any other concerns with the proposed standard that have not been covered by previous questions and comments? If so, please provide your feedback to the EOP SDT

Summary Consideration: Thank you for your comments.

SPP and Kansas City Power and Light provided comments to the revised defined term Energy Emergency and asked for clarification of Load obligation and whether this includes Contingency Reserves. The EOP SDT's intent was not for the Load obligation to include Contingency Reserves.

The Technical Justification has been updated to the current revisions of EOP-011-1.

First Energy and ISO New England Inc. suggested revision to Requirement R1 Part 1.2. and Requirement R2 Part 2.2. to delete the words "prepare for and" to prevent misinterpretation that would expand the scope of what the SDT intended for EOP-011-1. Specifically, when an abnormal system condition occurs, the condition may not immediately meet one or more of the three NERC "Emergency" definitions, but it could lead to an "Emergency" state. The EOP SDT drafted the language with the intent that preparing for Emergency conditions is a necessary part of mitigating operating Emergencies, therefore, the drafting team elected to retain the language as drafted.

DTE Electric commented on time periods be defined for Requirements R3 and R4. The EOP SDT maintains that Requirement R3 provides a 30-day time period; and that the time requirement in Requirement R4 is appropriately addressed by providing a mechanism by which the Reliability Coordinator is provided the operational flexibility necessary to account for variances in regional considerations.

Dominion commented: "Compliance section C, Compliance Monitoring and Assessment Processes,1.3; in other Standards Under Development (IRO-002-4 and others in Project 2014-03) Dominion noticed these items under this section have been removed and the below statement has been added to this section 'As defined in the NERC Rules of Procedure;' Compliance Monitoring and Assessment Processes' refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard.' If this is the direction NERC is headed, then EOP-011-1 needs to have Section 1.3 updated with the above statement for consistency." The EOP SDT agrees with Dominion's comment and has implemented this revision to Compliance Section C, Compliance Monitoring and Assessment Processes.

Seattle City Light commented that adding an explicit statement in EOP-011-1 that an entity registered as both a Transmission Operator and a Balancing Authority not be required to maintain two separate Operating Plans to demonstrate compliance with Requirements R1 and R2; that a single plan can be used to show compliance with these two requirements. The EOP SDT drafted the requirement with the intent that the Risk-based approach enables an entity to define the most appropriate methodology for plans for their entity. Rather than adding an explicit statement in the standard, however, the EOP SDT suggested clarifying language to be added in the RSAW.

Manitoba Hydro commented that the term “curtailable Load” is redundant in Requirement R2 Part 2.2.7., as it is inclusive in the definition of “Interruptible Load” in the NERC Glossary of Terms. The EOP SDT retained the term “curtailable Load” in the requirement part.

ACES Standards Collaborators commented about the inclusion of LSE in the proposed revised definition of Energy Emergency. SRC also commented on the revised definition of Energy Emergency and provided language revision suggestions. The EOP SDT retained the language as drafted and maintains that revisions necessitated by future changes will be addressed appropriately when they arise. The drafting team has made no revisions to the proposed revision of the defined term Energy Emergency.

BPA requested clarification of Requirement R5 methodology. The EOP SDT drafted the requirement with the intent that, under Risk-based approach, an entity is able to define the most appropriate electronic communications, or equivalent evidence for their entity.

Hydro-Quebec provided comments for clarification to Requirement R1 Parts. The EOP SDT drafted the language with the intention that the TOP would notify the RC of current and projected conditions. In addition, the EOP SDT drafted the language for consistency with the other Parts of Requirement R2 with the intent that the process to prepare for and mitigate Emergencies includes requests for redispatch of generation.

Additionally, Hydro-Quebec suggested that a Reliability Coordinator may have numerous Balancing Authorities and Transmission Operators in its Reliability Coordinator Area who are not necessarily affected by an emergency declared by one of them, and suggested using the term “impacted entities.” The EOP SDT believes that there is a reliability benefit to notifying other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area and neighboring Reliability Coordinators; such notification provides situational awareness for those entities.

Hydro-Quebec commented that there is no specific VSL if the Reliability Coordinator does not review the plans. The EOP SDT drafted language for the VSLs “identified a reliability risk” which would take place during a review of the plans. When reviewing the Operating Plan(s), the Reliability Coordinator is looking for deficiencies, inconsistencies, or conflicts between submitted plans that would cause further degradation to the BES during Emergency conditions. The EOP SDT believes that the VSLs are appropriate as written.

A comment was received stating that EOP-011-1 is not specific on which Operating Plan(s) the proposed standard addresses. The drafting team specifies in the Purpose statement “Operating Plan(s) to mitigate operating Emergencies.” In addition, Requirements R1 and R2 provide details regarding what should be included in the Operating Plan(s).

The EOP SDT has made corrective revisions to suggested punctuation, grammar and syntax in EOP-011-1 where merited.

Organization	Yes or No	Question 4 Comment
Arizona Public Service Company	No	
Northeast Power Coordinating Council	No	
MRO NERC Standards Review Forum	No	
Southern Company: Southern Company Services, Inc.; Alabama Power Company; Georgia Power Company; Gulf Power Company; Mississippi Power Company; Southern Company Generation; Southern Company Generation and Energy Marketing	No	
PPL NERC Registered Affiliates	No	
DTE Electric	No	Due to the lack of time being defined in Requirements 3 & 4, we are voting negative for this ballot period.
Duke Energy	No	
Peak Reliability	No	

Organization	Yes or No	Question 4 Comment
American Electric Power	No	
Idaho Power	No	
Tacoma Power	No	
We Energies	No	
Salt River Project	No	
Exelon Companies	No	
South Carolina Electric & Gas	No	
Texas Reliability Entity	No	
Tri-State Generation and Transmission Association, Inc.	No	
Dominion	Yes	Compliance section C, Compliance Monitoring and Assessment Processes,1.3; in other Standards Under Development (IRO-002-4 and others in Project 2014-03) Dominion has noticed these items under this section have been removed and the below statement has been added to this section "As defined in the NERC Rules of Procedure, "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard."If this is the direction NERC is headed, then EOP-011-1 needs to have Section 1.3 updated with the above statement for consistency.
Seattle City Light	Yes	Seattle City Light supports the proposed draft but asks for an explicit statement in the Standard that an entity registered as both a TOP and a BA is not required to maintain

Organization	Yes or No	Question 4 Comment
		two separate Operating Plans to demonstrate compliance with R1 (TOP plan) and R2 (BA plan), and that a single plan can be compliant so long as it address the required plan elements for both functions.
FirstEnergycorp	Yes	FIRSTENERGY supports the RSC comments which are reflected below but was not provided as an option before the ballots.The language in R1, Part 1.2 and R2, Part 2.2, which requires the Operating Plan to include, as applicable, "Processes to prepare for and mitigate Emergencies" is inconsistent with the Purpose of the Standard, that is, "...to mitigate operating Emergencies." The words "prepare for and" should be deleted from R1, Part 1.2 and R2, Part 2.2 because that language could be interpreted to expand the scope of what the SDT intended for EOP-011-1. Specifically, when an abnormal system condition occurs, the condition may not immediately meet one or more of the three NERC "Emergency" definitions, but it could lead to an "Emergency" state. TOPs and BAs take actions to address many abnormal system conditions and, as a result, those conditions never reach an "Emergency" state.. EOP-011-1 requires the development of an Operating Plan to address operating Emergencies. However, the "prepare for" language could lead to inappropriate (and greatly expanded) identification of implementations of an Operating Plan, because it could be interpreted to include actions that are taken before an Emergency state is reached.In a follow-up response to a question about this posed at the 10/8/14 Webinar on EOP-011-1, a member of the SDT responded as follows:"It was the intention of the EOP SDT in developing EOP-011-1 for plans to be implemented under Real-time conditions of Emergency and to mitigate those Emergency conditions. From a compliance standpoint, the EOP SDT was not looking at abnormal conditions that could lead to an Emergency state." Thus, it is clear that the words "prepare for and" should be deleted as described above because they are inconsistent with the standard's stated purpose and the EOP SDT's intention in developing EOP-011-1.
SPP Standards Review Group	Yes	Regarding the change of 'energy obligation' to 'Load obligation' in the definition of Energy Emergency, does the SDT believe that Load obligation includes Contingency

Organization	Yes or No	Question 4 Comment
		Reserves? According to the definition of Load in the NERC Glossary, it shouldn't. If it doesn't, then the shift in philosophy to shedding Load to maintain Contingency Reserves needs to be reflected in the definition of Energy Emergency.We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well.The Technical Justification document has not been updated to match the currently posted draft standard.
ACES Standards Collaborators	Yes	(1) We question the inclusion of LSE in proposed definition of Energy Emergency. The Risk Based Registration (RBR) project is proposing to remove the LSE function. If the LSE is retired, does this proposed definition logically make sense? The definition should be revised to remove the LSE and focus the activities on the Balancing Authority. Furthermore, unless the BA is also in an EEA it is highly unlikely for an individual LSE in the Host BA to be in an EEA as this implies there is excess energy available in the Host BA. The LSE should not be an applicable entity for EOP-011-1.(2) Thank you for the opportunity to comment.
ISO/RTO Council Standards Review Committee (SRC)	Yes	While the SRC agrees that entities need to be forecasting conditions and taking actions to address deficiencies prior to real-time, the SRC disagrees with the revisions made to the term "Energy Emergency". The posting indicates that revisions were made solely to recognize that Load-Serving Entities are not the only entities that may declare an Energy Emergency. However, additional revisions appear to bring forecasted conditions within the definition of "Energy Emergency". The SRC assesses that, while the forecasting of potential deficiency conditions is important, use of the term "Energy Emergency" should be reserved for those conditions where an entity is truly "energy deficient" regarding serving its Load obligations, i.e., at an Energy Emergency Alert level 2 or above. The SRC proposes the following revisions be made to the definition of Energy Emergency:Energy Emergency - A condition when a Load-Serving Entity or Balancing Authority has exhausted all other options and can no longer provide sufficient energy to meet its Load obligations.

Organization	Yes or No	Question 4 Comment
Bonneville Power Administration	Yes	BPA requests verification/clarification of R5 notification methodology: Will WECCNet suffice as "electronic communications, or equivalent evidence"? BPA believes it would be unrealistic for the RC to all of the BA/TOPs in its footprint (50-100 or more) within 30 minutes by any any other manner.
Kansas City Power and Light	Yes	Regarding the change of 'energy obligation' to 'Load obligation' in the definition of Energy Emergency, does the SDT believe that Load obligation includes Contingency Reserves? According to the definition of Load in the NERC Glossary, it shouldn't. If it doesn't, then the shift in philosophy to shedding Load to maintain Contingency Reserves needs to be reflected in the definition of Energy Emergency.We recommend that all changes we proposed to be made to the standard be reflected in the RSAW as well.The Technical Justification document has not been updated to match the currently posted draft standard.
Hydro-Quebec TransEnergie	Yes	R1 - Paragraphs 1.2.1 and 1.2.4 are ambiguousRegarding 1.2.1, two possible interpretationsa) TOP should notify RC of current and projected conditions. 1.2.1. Notification to the Reliability Coordinator of current and projected conditions, when experiencing an operating Emergency;b) However, If the purpose is for TOP to notify RC to actually include the current and projected conditions, then the following question is to include them in what? In that case, there is a part of the sentence that is missing.Regarding 1.2.4, the phrasing is ambiguous: 2 possible interpretations and rephrasings depending on if the purpose of the process is to redispatch or to request redispatch.a) 1.2 Process to prepare for and mitigate Emergencies including: 1.2.4. Redispatch of generationb) 1.2 Process to prepare for and mitigate Emergencies including: 1.2.4 Request for redispatch of generationR2- Same comments apply to 2.2.1 as those made regarding 1.2.1R3 - Table of Compliance ElementsThere is no VSL if the RC does not review the Plan. We suggest that this be added to the Severe VSL .R5- A RC may have numerous BA and TOP in its RC area who are not necessarily affected by an emergency declared by one of them. We suggest the use of the same terminology as that used in the Table of Compliance section of the standard which

Organization	Yes or No	Question 4 Comment
		refers to impacted entities. Therefore, R5 would read:Each RC that receives an Emergency notification from a TOP or BA shall notify, within 30 minutes from the time of receiving notification, other impacted or potentially impacted BA and TOP in its RC Area, and neighboring RCs,Same comment applies to M5.Attachment 1, section 3.3.1.: there is a typographical error.The energy deficient BA, upon notification from its RC of the situation, it will immediately take whatever actions are necessary (...)
Manitoba Hydro	Yes	Requirement R2.2.7 “Use of Interruptible Load, curtailable Load and demand response.” The term curtailable Load is redundant as it is already included in the definition of” Interruptible Load in the “Glossary of Terms Used in NERC Reliability Standards” as “Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.”
ISO New England Inc.	Yes	The language in R1, Part 1.2 and R2, Part 2.2, which requires the Operating Plan to include, as applicable, "Processes to prepare for and mitigate Emergencies" is inconsistent with the Purpose of the Standard, that is, "...to mitigate operating Emergencies." The words "prepare for and" should be deleted from R1, Part 1.2 and R2, Part 2.2 because that language could be interpreted to expand the scope of what the SDT intended for EOP-011-1. Specifically, when an abnormal system condition occurs, the condition may not immediately meet one or more of the three NERC “Emergency” definitions, but it could lead to an “Emergency” state. TOPs and BAs take actions to address many abnormal system conditions and, as a result, those conditions never reach an “Emergency” state.. EOP-011-1 requires the development of an Operating Plan to address operating Emergencies. However, the “prepare for” language could lead to inappropriate (and greatly expanded) identification of implementations of an Operating Plan, because it could be interpreted to include actions that are taken before an Emergency state is reached.In a follow-up response to a question about this posed at the 10/8/14 Webinar on EOP-011-1, a member of the SDT responded as follows:”It was the intention of the EOP SDT in developing EOP-011-1 for plans to be implemented under Real-time conditions of Emergency and to

Organization	Yes or No	Question 4 Comment
		mitigate those Emergency conditions. From a compliance standpoint, the EOP SDT was not looking at abnormal conditions that could lead to an Emergency state.” Thus, it is clear that the words “prepare for and” should be deleted as described above because they are inconsistent with the standard’s stated purpose and the EOP SDT’s intention in developing EOP-011-1.

Additional Comments:

LCRA
Dixie Wells

EOP-011-1 is not specific enough on which operating plans it addresses.

END OF REPORT

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The North American Electric Corporation (NERC) Standards Committee authorized moving the Standards Authorization Request (SAR) forward to standard development 10/17/2013.
2. SAR posted for comment 11/06/13-12/05/13.
3. Informal posting for comment 03/28/14-04/28/14.
4. Initial formal posting for comment with parallel initial ballot 07/02/14-08/15/14.
5. Additional formal posting for comment with parallel additional ballot 09/05/14-10/20/14.

Description of Current Draft

This is the third draft of the proposed standard and is being posted for final ballot. This draft includes the modifications based on the Five-Year Review Team recommendations, comments submitted by stakeholders during the SAR comment period, the informal comment period, the formal comment period, other items identified in the SAR, and applicable Federal Energy Regulatory Commission (FERC) directives from FERC Order No. 693.

Anticipated Actions	Anticipated Date
Additional 45-day Formal Comment Period with Parallel Initial Ballot	September 2014
Final ballot	October 2014
BOT adoption	November 2014

Effective Dates

See *Implementation Plan for EOP-011-1*

Version History

Version	Date	Action	Change Tracking
1	TBD	Initial Standard	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

Definitions of Terms Used in Standard

This section includes all newly-defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The Emergency Operations Standard Drafting Team (EOP SDT) proposes to revise the current approved definition of **Energy Emergency** as follows:

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its ~~customers'~~ expected ~~energy~~ Load obligations.

The proposed revisions are intended to clarify that an Energy Emergency is not necessarily limited to a Load-Serving Entity. This term, or variations of it, is also used in other standards, as indicated below. The EOP SDT is obligated to review other standards in which this term is used to determine if reliability gaps or redundancies are created by the proposed revision to the defined term. The EOP SDT has determined that the proposed revisions do not change the reliability intent of other requirements or definitions. The following is a list of standards and definitions using the term:

- **BAL-002-WECC – Contingency Reserve**: This standard became enforceable on October 1, 2014. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **IRO-005-3.1a — Reliability Coordination — Current Day Operations** - This standard was revised under Project 2006-06 and the reference to Energy Emergency was removed from the standard. The standard was approved by the NERC Board of Trustees (Board) and filed with FERC. NERC has requested that FERC defer action on its petition and is revising this standard under Project 2014-03, TOP/IRO Reliability Standards. This project is scheduled to be completed no later than January 31, 2015. The two standard drafting teams are coordinating the definition revision to ensure there are no redundancies.
- **MOD-004-1 — Capacity Benefit Margin:** This standard is being retired and replaced with MOD-001-2 — Modeling, Data, and Analysis — Available Transmission System Capability (NERC Board approved February 6, 2014). The term "Energy Emergency" is not used in the new standard. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability to the existing approved standard.
- **INT-004-3 – Dynamic Transfers:** This standard was a revision to INT-004-2 under Project 2008-12. INT-004-3 was approved by the NERC Board and filed with FERC. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **Defined term Emergency Request for Interchange:** This term is not used in any existing approved standard.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title:** **Emergency Operations**

2. **Number:** **EOP-011-1**

3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plan(s) to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator Area.

4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator

5. **Background:**

   EOP-011-1 consolidates requirements from three standards: EOP-001-2.1b, EOP-002-3.1, and EOP-003-2.

   The standard streamlines the requirements for Emergency operations for the Bulk Electric System into a clear and concise standard that is organized by Functional Entity. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

1.2.6. Reliability impacts of extreme weather conditions.

Rationale for Requirement R1:

The EOP SDT examined the recommendation of the EOP Five-Year Review Team (FYRT) and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Transmission Operator to create an Operating Plan(s) for mitigating operating Emergencies in its Transmission Operator Area.

The Operating Plan(s) can be one plan, or it can be multiple plans.

"Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency" was retained. This is a process in the plan(s) that determines when the Transmission Operator must notify its Reliability Coordinator.

To meet the associated measure, an entity would likely provide evidence that such an evaluation was conducted along with an explanation of why any overlap of Loads between manual and automatic load shedding was unavoidable or reasonable.

An Operating Plan(s) is implemented by carrying out its stated actions.

If any Parts of Requirement R1 are not applicable, the Transmission Operator should note "not applicable" in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s).

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shed schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R1 Part 1.2.5. is to minimize, as much as possible, the use of manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If any entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review their automatic Load shedding schemes and coordinate their manual processes so that any overlapping use of Loads is avoided to the extent reasonably possible.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

2.2.9. Reliability impacts of extreme weather conditions.

Rationale for Requirement R2: To address the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1, the EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. EOP-011-1 also establishes a separate requirement for the Balancing Authority to create its Operating Plan(s) to address Capacity and Energy Emergencies.

The Operating Plan(s) can be one plan, or it can be multiple plans.

An Operating Plan(s) is implemented by carrying out its stated actions.

If any Parts of Requirement R2 are not applicable, the Balancing Authority should note "not applicable" in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s).

The EOP SDT retained the statement "Operator-controlled manual Load shedding," as it was in the current EOP-003-2 and is consistent with the intent of the EOP SDT.

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shedding schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R2 Part 2.2.8. is to minimize as much as possible the use manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If an entity manually sheds a Load that was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review its automatic Load shedding schemes and coordinate its manual processes so that any overlapping use of Loads is avoided to the extent possible.

The EOP SDT retained Requirement R8 from EOP-002-3.1 and added it to the Parts in Requirement R2.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator shall review the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning]*

3.1. Within 30 calendar days of receipt, the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified.

Rationale for R3: The SDT agreed with industry comments that the Reliability Coordinator does not need to approve BA and TOP plan(s). The SDT has changed this requirement to remove the approval but still require the RC to review each entity's plan(s), looking specifically for reliability risks. This is consistent with the Reliability Coordinator's role within the Functional Model and meets the FERC directive regarding the RC's involvement in Operating Plan(s) for mitigating Emergencies.

M3. The Reliability Coordinator will have documentation, such as dated e-mails or other correspondences that it reviewed Transmission Operator and Balancing Authority Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

Rationale for Requirement R4: Requirement R4 supports the coordination of Operating Plans within a Reliability Coordinator Area in order to identify and correct any Wide Area reliability risks. The EOP SDT expects the Reliability Coordinator to make a reasonable request for response time. The time period requested by the Reliability Coordinator to the Transmission Operator and Balancing Authority to update the Operating Plan(s) will depend on the scope and urgency of the requested change.

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R5: The EOP SDT used the existing requirement in EOP-002-3.1 for the Balancing Authority and added the words "within 30 minutes from the time of receiving notification" to the requirement to communicate the intent that timeliness is important, while balancing the concern that in an Emergency there may be a need to alleviate excessive notifications on Balancing Authorities and Transmission Operators. By adding this time limitation, a measurable standard is

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators .

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The Balancing Authority, Reliability Coordinator, and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4and Measures M1 and M4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

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

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

1.3. Compliance Monitoring and Assessment Processes:

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

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Real-time Operations, Operations Planning, Long-term Planning**	**High**		The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to have it reviewed by its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission s Operator Area but failed to implement it.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	**Real-time Operations, Operations Planning, Long-term Planning**	**High**	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to have it reviewed by its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to implement it.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	**Operations Planning**	**High**	N/A	N/A	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator.
R4	**Operations Planning**	**High**	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit tis Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
R5	**Real-time Operations**	**High**	N/A	N/A	The Reliability Coordinator that received an	The Reliability Coordinator that received an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators but failed to notify within 30 minutes from the time of receiving notification.	Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	**Real-time Operations**	**High**	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency Alert.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Attachment 1-EOP-011-1
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

Rationale for Introduction: LSEs were removed from Attachment 1, as an LSE has no Real-time reliability functionality with respect to EEAs.

EOP-002-3.1 Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, as permitted in its transmission tariff, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ E-tag Specification v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.
2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all neighboring Reliability Coordinators.

Rationale for (2) Notification: The EOP SDT deleted the language, "*The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between RCs shall be held as necessary to communicate system conditions. The RC shall also notify the other RCs when the alert has ended*" as duplicative to proposed IRO-014-3 Requirement R1:

R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:

1.1 Communications and notifications, and the process to follow in making those notifications.

1.2 Energy and capacity shortages.

1.3 Control of voltage, including the coordination of reactive resources.
Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

1.5 Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas.

1.6 Provisions for weekly conference calls.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinators clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinators will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. EEA 1 — All available generation resources in use.

Circumstances:

- The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. EEA 2 — Load management procedures in effect.

Circumstances:

- The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
- An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.
- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinators and energy deficient Balancing Authorities have the following responsibilities:

2.1 Notifying other Balancing Authorities **and market participants**. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. Other Reliability Coordinators of Balancing Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

Rationale for EEA 2: The EOP SDT modified the "Circumstances" for EEA 2 to show that an entity will be in this level when it has implemented its Operating Plan(s) to mitigate Emergencies but is still able to maintain Contingency Reserves.

3. EEA 3 —Firm Load interruption is imminent or in progress.

Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinators and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinators and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 **Energy deficient Balancing Authority obligations.** The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 **Returning to pre-Emergency conditions.** Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre-Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 **Notification of other parties.** Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the neighboring Reliability Coordinators (via the RCIS), Balancing Authorities and Transmission Operators that its Systems can be returned to its normal limits.

Rationale for EEA 3:

This rationale was added at the request of stakeholders asking for justification for moving a lack of Contingency Reserves into the EEA3 category.

The previous language in EOP-002-3.1, EEA 2 used “Operating Reserve,” which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently. Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using minimum Contingency Reserve in the language would eliminate some of the confusion. This is a different approach but the drafting team believes this is a good approach and was supported by several commenters.

Using Contingency Reserves (which is a subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that the point where a BA can no longer maintain this important Contingency Reserves margin is a most serious condition and puts the BA into a position where they are very close to shedding Load (“imminent or in progress”). The drafting team felt that this warrants categorization at the highest level of EEA.

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA**.**

0.1 **Notification.** The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the neighboring Balancing Authorities and Transmission Operators.

Guidelines and Technical Basis

Rationales to be added here after balloting.

Requirement R1:

Requirement R2:

Requirement R3:

Requirement R4:

Requirement R5:

Requirement R6:

Standard Development Timeline

This section is maintained by the drafting team during the development of the standard and will be removed when the standard becomes effective.

Development Steps Completed

1. The North American Electric Corporation (NERC) Standards Committee authorized moving the Standards Authorization Request (SAR) forward to standard development 10/17/2013.
2. SAR posted for comment 11/06/13-12/05/13.
3. Informal posting for comment 03/28/14-04/28/14.
4. Initial formal posting for comment with parallel initial ballot 07/02/14-08/15/14.
5. ~~4.~~5.Additional formal posting for comment with parallel additional ballot 09/05/14-10/20/14.

Description of Current Draft

This is the third draft of the proposed standard and is being posted for ~~formal stakeholder comments and initial~~final ballot. This draft includes the modifications based on the Five-Year Review Team recommendations, comments submitted by stakeholders during the SAR comment period, the informal comment period, the formal comment period, other items identified in the SAR, and applicable Federal Energy Regulatory Commission (FERC) directives from FERC Order No. 693.

Anticipated Actions	Anticipated Date
Additional 45-day Formal Comment Period with Parallel Initial Ballot	September 2014
Final ballot	October 2014
BOT adoption	November 2014

Effective Dates

~~The standard shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard shall become effective on the first day of the first calendar quarter that is12 months after the date the standard is adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.~~See *Implementation Plan for EOP-011-1*

Version History

Version	Date	Action	Change Tracking
1	TBD	Initial Standard	Merged EOP-001-2.1b, EOP-002-3.1 and EOP-003-2.

Definitions of Terms Used in Standard

This section includes all newly-defined or revised terms used in the proposed standard. Terms already defined in the Reliability Standards Glossary of Terms (Glossary) are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

The Emergency Operations Standard Drafting Team (EOP SDT) proposes to revise the current approved definition of **Energy Emergency** as follows:

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its ~~customers'~~ expected ~~energy~~ Load obligations.

The proposed revisions are intended to clarify that an Energy Emergency is not necessarily limited to a Load-Serving Entity. This term, or variations of it, ~~are~~ is also used in other standards, as indicated below. The EOP SDT is obligated to review other standards in which this term is used to determine if reliability gaps or redundancies are created by the proposed revision to the defined term. The EOP SDT ~~does not believe~~has determined that the proposed revisions do not change the reliability intent of other requirements or definitions. The following is a list of standards and definitions using the term:

- **BAL-002-WECC – Contingency Reserve**: This standard ~~becomes~~ became enforceable on October 1, 2014. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **IRO-005-3.1a — Reliability Coordination — Current Day Operations** - This standard was revised under Project 2006-06 and the reference to Energy Emergency was removed from the standard. The standard was approved by the NERC Board of Trustees (Board)~~BOT~~ and filed with FERC. NERC has requested that FERC defer action on its petition and is revising this standard under Project 2014-03, TOP/IRO Reliability Standards. This project is scheduled to be completed no later than January 31, 2015. The two standard drafting teams are coordinating the definition revision to ensure there are no redundancies.
- **MOD-004-1 — Capacity Benefit Margin:** This standard is being retired and replaced with MOD-001-2 — Modeling, Data, and Analysis — Available Transmission System Capability (NERC ~~BOT~~ Board approved February 6, 2014). The term "Energy Emergency" is not used in the new standard. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability to the existing approved standard.
- **INT-004-3 – Dynamic Transfers:** This standard was a revision to INT-004-2 under Project 2008-12. INT-004-3 was approved by the NERC ~~BOT~~ Board and filed with FERC. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **Defined term Emergency Request for Interchange:** This term is not used in any existing approved standard.

When this standard has received ballot approval, the text boxes will be moved to the Application Guidelines Section of the Standard.

A. Introduction

1. **Title: Emergency Operations**
2. **Number: EOP-011-1**
3. **Purpose:** To address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plan(s) to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator Area.
4. **Applicability:**

   4.1. Functional Entities:

   4.1.1 Balancing Authority

   4.1.2 Reliability Coordinator

   4.1.3 Transmission Operator
5. **Background:**

   EOP-011-1 consolidates requirements from three standards: EOP-001-2.1b, EOP-002-3.1, and EOP-003-2.

   The standard streamlines the requirements for Emergency operations for the Bulk Electric System ~~(BES)~~ into a clear and concise standard that is organized by Functional Entity. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

B. Requirements and Measures

R1. Each Transmission Operator shall develop, maintain, and implement ~~a~~ one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

1.1. Roles and responsibilities for activating the Operating Plan(s);

1.2. Processes to prepare for and mitigate Emergencies including:

1.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency;

1.2.2. Cancellation or recall of Transmission and generation outages;

1.2.3. Transmission system reconfiguration;

1.2.4. Redispatch of generation request;

1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

1.2.6. Reliability impacts of extreme weather conditions.

Rationale for Requirement R1:

The EOP SDT examined the recommendation of the EOP Five-Year Review Team (FYRT) and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. This also establishes a separate requirement for the Transmission Operator to create an Operating Plan(s) for mitigating operating Emergencies in its Transmission Operator Area.

The Operating Plan(s) can be one plan, or it can be multiple plans.

"Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency" was retained. This is a process in the plan(s) that determines ~~how~~ when the Transmission Operator~~you will make a notification to the~~ must notify its Reliability Coordinator.

To meet the associated measure, an entity would likely provide evidence that such an evaluation was conducted along with an explanation of why any overlap of Loads between manual and automatic load shedding was unavoidable or reasonable.

An Operating Plan(s) is implemented by carrying out its stated actions.

If any Parts of Requirement R1 are not applicable, the Transmission Operator should note "not applicable" in the Operating ~~plan~~Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s).

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shed schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R1 Part 1.2.~~6~~ 5. is to minimize, as much as possible, the use of manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If any entity manually sheds a Load which was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review their automatic Load shedding schemes and coordinate their manual processes so that any overlapping use of Loads is avoided to the extent reasonably possible.

M1. Each Transmission Operator will have a dated Operating Plan(s) developed in accordance with Requirement R1 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R1.

R2. Each Balancing Authority shall develop, maintain, and implement ~~a~~ one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]*

2.1. Roles and responsibilities for activating the Operating Plan(s);

2.2. Processes to prepare for and mitigate Emergencies including:

2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

2.2.2. Requesting an Energy Emergency Alert, per Attachment 1;

2.2.3. Managing generating resources in its Balancing Authority Area to address:

2.2.3.1. capability and availability;

2.2.3.2. fuel supply and inventory concerns;

2.2.3.3. fuel switching capabilities; and

2.2.3.4. environmental constraints.

2.2.4. Public appeals for voluntary Load reductions;

2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions;

2.2.6. Reduction of internal utility energy use;

2.2.7. Use of Interruptible Load, curtailable Load and demand response;

2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

2.2.9. Reliability impacts of extreme weather conditions.

Rationale for Requirement R2: To address the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1, the EOP SDT removed EOP-001-2.1b, Attachment 1, and incorporated it into this standard under the applicable requirements. EOP-011-1 also establishes a separate requirement for the Balancing Authority to create its ~~Emergency~~ Operating Plan(s) to address Capacity and Energy Emergencies.

The Operating Plan(s) can be one plan, or it can be multiple plans.

An Operating Plan(s) is implemented by carrying out its stated actions.

If any Parts of Requirement R2 are not applicable, the Balancing Authority should note "not applicable" in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s).

The EOP SDT retained the statement "Operator-controlled manual Load shedding," as it was in the current EOP-003-2 and is consistent with the intent of the EOP SDT.

With respect to automatic Load shedding schemes that include both UVLS and UFLS, the EOP SDT's intent is to keep manual and automatic Load shedding schemes as separate as possible, but realizes that sometimes, due to system design, there will be overlap. The intent in Requirement R2 Part 2.2.8. is to minimize as much as possible the use manual Load shedding which is already armed for automatic Load shedding. The automatic Load shedding schemes are the important backstops against Cascading outages or System collapse. If an entity manually sheds a Load that was included in an automatic scheme, it reduces the effectiveness of that automatic scheme. Each entity should review its automatic Load shedding schemes and coordinate its manual processes so that any overlapping use of Loads is avoided to the extent possible.

The EOP SDT retained Requirement R8 from EOP-002-3.1 and added it to the Parts in Requirement R2.

M2. Each Balancing Authority will have a dated Operating Plan(s) developed in accordance with Requirement R2 and reviewed by its Reliability Coordinator; evidence such as a review or revision history to indicate that the Operating Plan(s) has been maintained; and will have as evidence, such as operator logs or other operating documentation, voice recordings, or other communication documentation to show that its Operating Plan(s) was implemented for times when an Emergency has occurred, in accordance with Requirement R2.

R3. The Reliability Coordinator~~, within 30 calendar days of receipt,~~ shall review ~~each~~ the Operating Plan(s) to mitigate operating Emergencies submitted by a Transmission Operator or a Balancing Authority regarding any reliability risks that are identified between Operating Plans. *[Violation Risk Factor: High] [Time Horizon: Operations Planning-]*

3.1. Within 30 calendar days of receipt, ~~The~~ the Reliability Coordinator shall:

3.1.1. Review each submitted Operating Plan(s) on the basis of compatibility and inter-dependency with other Balancing Authorities' and Transmission Operators' Operating Plans;

3.1.2. Review each submitted Operating Plan(s) for coordination to avoid risk to Wide Area reliability; and

3.1.3. Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified. ~~*[Violation Risk Factor: High] [Time Horizon: Operations Planning]*~~

Rationale for R3: The SDT agreed with industry comments that the Reliability Coordinator does not need to approve BA and TOP plan(s). The SDT has changed this requirement to remove the approval but still require the RC to review each entity's plan(s), looking specifically for reliability risks. This is consistent with the Reliability Coordinator's role within the Functional Model and meets the FERC directive regarding the RC's involvement in Operating Plan(s) for mitigating ~~emergencies~~Emergencies.

M3. The Reliability Coordinator will have documentation, such as dated e-mails or other correspondences that it reviewed Transmission Operator and Balancing Authority Operating Plans within 30 calendar days of submittal in accordance with Requirement R3.

R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to its Reliability Coordinator within a time period specified by its Reliability Coordinator. *[Violation Risk Factor: High] [Time Horizon: Operation Planning]*

Rationale for Requirement R4: Requirement R4 supports the coordination of Operating Plans within a Reliability Coordinator Area in order to identify and correct any Wide Area reliability risks. The EOP SDT expects the Reliability Coordinator to make a reasonable request for response time. The time period requested by the Reliability Coordinator to the Transmission Operator and Balancing Authority to update the Operating Plan(s) will depend on the scope and urgency of the requested change.

M4. The Transmission Operator and Balancing Authority will have documentation, such as dated emails or other correspondence, with an Operating Plan(s) version history showing that it responded and updated the Operating Plan(s) within the timeframe identified by its Reliability Coordinator in accordance with Requirement R4.

R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

Rationale for R5: The EOP SDT used the existing requirement in EOP-002-3.1 for the Balancing Authority and added the words "within 30 minutes from the time of receiving notification" to the requirement to communicate the intent that timeliness is important, while balancing the concern that in an Emergency there may be a need to alleviate excessive notifications on Balancing Authorities and Transmission Operators. By adding this time limitation, a measurable standard is set for when the Reliability Coordinator must complete these notifications.

M5. Each Reliability Coordinator that receives an Emergency notification from a Balancing Authority or Transmission Operator within its Reliability Coordinator Area will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that will be used to determine if the Reliability Coordinator communicated, in accordance with Requirement R5, with other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators .

R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*

~~**Rationale for R6**: Requirement R6 was created to address the FERC directive to have the Reliability Coordinator involved to ensure that the Energy Emergency Alert is declared.~~

M6. Each Reliability Coordinator, with a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area, will have, and provide upon request, evidence that could include, but is not limited to, operator logs, voice recordings or transcripts of voice recordings, electronic communications, or equivalent evidence that it declared an Energy Emergency Alert, as detailed in Attachment 1, in accordance with Requirement R6.

C. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

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

1.2. Evidence Retention

The Balancing Authority, Reliability Coordinator, and Transmission Operator shall keep data or evidence to show compliance, as identified below, unless directed by its Compliance Enforcement Authority (CEA) to retain specific evidence for a longer period of time as part of an investigation. For instances where the evidence retention period specified below is shorter than the time since the last audit, the CEA may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- The Transmission Operator shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R1 and R4and Measures M1 and M4.
- The Balancing Authority shall retain the current Operating Plan(s), evidence of review or revision history plus each version issued since the last audit and evidence of compliance since the last audit for Requirements R2 and R4, and Measures M2 and M4.
- The Reliability Coordinator shall maintain evidence of compliance since the last audit for Requirements R3, R5, and R6 and Measures M3, M5, and M6.

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

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

1.3. Compliance Monitoring and Assessment Processes:

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

~~ompliance Audit~~

~~Self-Certification~~

~~Spot Check~~

~~Compliance Investigation~~

~~Self-Report~~

~~Complaint~~

1.4. Additional Compliance Information

None

Table of Compliance Elements

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R1	**Real-time Operations, Operations Planning, Long-term Planning**	**High**		The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies ~~on~~ in its Transmission Operator Area but failed to maintain it.	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to have it reviewed by ~~the~~ its Reliability Coordinator.	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission s Operator Area but failed to implement it.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R2	**Real-time Operations, Operations Planning, Long-term Planning**	**High**	N/A	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to maintain it.	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to have it reviewed by ~~the~~ its Reliability Coordinator.	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to implement it.

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
R3	**Operations Planning**	**High**	N/A	N/A	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator.
R4	**Operations Planning**	**High**	N/A	N/A	The Transmission Operator or Balancing Authority failed to update and resubmit ~~the~~ tis Operating Plan(s) to ~~the~~ its Reliability Coordinator within the timeframe specified by ~~the~~ its Reliability Coordinator.	The Transmission Operator or Balancing Authority failed to update and resubmit ~~the~~ its Operating Plan(s) to ~~the~~ its Reliability Coordinator.
R5	**Real-time Operations**	**High**	N/A	N/A	The Reliability Coordinator that received an	The Reliability Coordinator that received an

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
					Emergency notification from a Transmission Operator or Balancing Authority did notify ~~impacted~~ neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators but failed to ~~did not~~ notify within 30 minutes from the time of receiving notification.	Emergency notification from a Transmission Operator or Balancing Authority failed to notify ~~impacted~~ neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
R6	**Real-time Operations**	**High**	N/A	N/A	N/A	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency

R #	Time Horizon	VRF	Violation Severity Levels			
			Lower VSL	Moderate VSL	High VSL	Severe VSL
						Alert.

D. Regional Variances

None.

E. Interpretations

None.

F. Associated Documents

None.

Attachment 1-EOP-011-1
Energy Emergency Alerts

Introduction

This Attachment provides the process and descriptions of the levels used by the Reliability Coordinator in which it communicates the condition of a Balancing Authority which is experiencing an Energy Emergency.

Rationale for Introduction: LSEs were removed from Attachment 1, as an LSE has no Real-time reliability functionality with respect to EEAs.

EOP-002-3.1 Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, as permitted in its transmission tariff, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ E-tag Specification v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.

A. General Responsibilities

1. **Initiation by Reliability Coordinator.** An Energy Emergency Alert (EEA) may be initiated only by a Reliability Coordinator at 1) the Reliability Coordinator's own request, or 2) upon the request of an energy deficient Balancing Authority.

2. **Notification**. A Reliability Coordinator who declares an EEA shall notify all Balancing Authorities and Transmission Operators in its Reliability Coordinator Area. The Reliability Coordinator shall also notify all ~~adjacent~~ neighboring Reliability Coordinators.

Rationale for (2) Notification: The EOP SDT deleted the language, "*The Reliability Coordinator shall also notify all other Reliability Coordinators of the situation via the Reliability Coordinator Information System (RCIS). Additionally, conference calls between RCs shall be held as necessary to communicate system conditions. The RC shall also notify the other RCs when the alert has ended*" as duplicative to proposed IRO-014-3 Requirement R1:

R1. Each Reliability Coordinator shall have and implement Operating Procedures, Operating Processes, or Operating Plans, for activities that require notification or coordination of actions that may impact adjacent Reliability Coordinator Areas, to support Interconnection reliability. These Operating Procedures, Operating Processes, or Operating Plans shall include, but are not limited to, the following:

1.1 Communications and notifications, and the process to follow in making those notifications.

1.2 Energy and capacity shortages.

1.3 Control of voltage, including the coordination of reactive resources.
Exchange of information including planned and unplanned outage information to support its Operational Planning Analyses and Real-time Assessments.

1.5 Authority to act to prevent and mitigate system conditions which could adversely impact other Reliability Coordinator Areas.

1.6 Provisions for weekly conference calls.

B. EEA Levels

Introduction

To ensure that all Reliability Coordinator~~-~~s clearly understand potential and actual Energy Emergencies in the Interconnection, NERC has established three levels of EEAs. The Reliability Coordinator~~-~~s will use these terms when communicating Energy Emergencies to each other. An EEA is an Emergency procedure, not a daily operating practice, and is not intended as an alternative to compliance with NERC Reliability Standards.

The Reliability Coordinator may declare whatever alert level is necessary, and need not proceed through the alerts sequentially.

1. EEA 1 — All available generation resources in use.

Circumstances:

- The Balancing Authority is experiencing conditions where all available generation resources are committed to meet firm Load, firm transactions, and reserve commitments, and is concerned about sustaining its required Contingency Reserves.

- Non-firm wholesale energy sales (other than those that are recallable to meet reserve requirements) have been curtailed.

2. EEA 2 — Load management procedures in effect.

Circumstances:

- The Balancing Authority is no longer able to provide its expected energy requirements and is an energy deficient Balancing Authority.
- An energy deficient Balancing Authority has implemented its Operating Plan(s) to mitigate Emergencies.
- An energy deficient Balancing Authority is still able to maintain minimum Contingency Reserve requirements.

During EEA 2, Reliability Coordinator~~-~~s and energy deficient Balancing Authorities~~-s~~ have the following responsibilities:

2.1 Notifying other Balancing Authorities **and market participants**. The energy deficient Balancing Authority shall communicate its needs to other Balancing Authorities and market participants. Upon request from the energy deficient Balancing Authority, the respective Reliability Coordinator shall post the declaration of the alert level, along with the name of the energy deficient Balancing Authority on the RCIS website.

2.2 Declaration period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 2 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the ~~impacted~~ neighboring Reliability Coordinator~~-~~s, Balancing Authorities and Transmission Operators**.**

2.3 Sharing information on resource availability. ~~The~~ Other Reliability Coordinators of ~~a~~ Balancing ~~Authority~~ Authorities with available resources shall coordinate, as appropriate, with the Reliability Coordinator that has an energy deficient Balancing Authority.

2.4 Evaluating and mitigating Transmission limitations. The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements that may relieve the loading on System Operating Limits (SOLs) or Interconnection Reliability Operating Limits (IROLs).

2.5 Requesting Balancing Authority actions. Before requesting an EEA 3, the energy deficient Balancing Authority must make use of all available resources; this includes, but is not limited to:

2.5.1 All available generation units are on line. All generation capable of being on line in the time frame of the Emergency is on line.

2.5.2 Demand-Side Management. Activate Demand-Side Management within provisions of any applicable agreements.

Rationale for EEA 2: The EOP SDT modified the "Circumstances" for EEA 2 to show that an entity will be in this level when it has implemented its Operating Plan(s) to mitigate Emergencies but is still able to maintain Contingency ~~reserves~~Reserves.

3. EEA 3 —Firm Load interruption is imminent or in progress.

Circumstances:

- The energy deficient Balancing Authority is unable to meet minimum Contingency Reserve requirements.

During EEA 3, Reliability Coordinators and Balancing Authorities have the following responsibilities:

3.1 Continue actions from EEA 2. The Reliability Coordinator~~-~~s and the energy deficient Balancing Authority shall continue to take all actions initiated during EEA 2.

3.2 Declaration Period. The energy deficient Balancing Authority shall update its Reliability Coordinator of the situation at a minimum of every hour until the EEA 3 is terminated. The Reliability Coordinator shall update the energy deficiency information posted on the RCIS website as changes occur and pass this information on to the ~~impacted~~ neighboring Reliability Coordinator~~-~~s, Balancing Authorities, and Transmission Operators.

3.3 Reevaluating and revising SOLs and IROLs. The Reliability Coordinator shall evaluate the risks of revising SOLs and IROLs for the possibility of delivery of energy to the energy deficient Balancing Authority. Reevaluation of SOLs and IROLs shall be coordinated with other Reliability Coordinator~~-~~s and only with the agreement of the Transmission Operator whose Transmission Owner (TO) equipment would be affected. SOLs and IROLs shall only be revised as long as an EEA 3 condition exists, or as allowed by the Transmission ~~Operator~~ Owner whose equipment is at risk. The following are minimum requirements that must be met before SOLs or IROLs are revised:

3.3.1 Energy deficient Balancing Authority obligations. The energy deficient Balancing Authority, upon notification from its Reliability Coordinator of the situation, it will immediately take whatever actions are necessary to mitigate any undue risk to the Interconnection. These actions may include Load shedding.

3.4 Returning to pre-Emergency conditions. Whenever energy is made available to an energy deficient Balancing Authority such that the Systems can be returned to its pre-Emergency SOLs or IROLs condition, the energy deficient Balancing Authority shall request the Reliability Coordinator to downgrade the alert level.

3.4.1 Notification of other parties. Upon notification from the energy deficient Balancing Authority that an alert has been downgraded, the Reliability Coordinator shall notify the ~~impacted~~ neighboring Reliability Coordinators (via the RCIS), Balancing Authorities and Transmission Operators that its Systems can be returned to its normal limits.

Rationale for EEA 3:

This rationale was added at the request of stakeholders asking for justification for moving a lack of Contingency Reserves into the EEA3 category.

The previous language in EOP-002-3.1, EEA 2 used "Operating Reserve," which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently. Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using minimum Contingency Reserve in the language would eliminate some of the confusion. This is a different approach but the drafting team believes this is a good approach and was supported by several commenters.

Using Contingency Reserves (which is a subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that the point where a BA can no longer maintain this important Contingency Reserves margin is a most serious condition and puts the BA into a position where they are very close to shedding Load ("imminent or in progress"). The drafting team felt that this warrants categorization at the highest level of EEA.

~~**3.4.1**~~

Alert 0 - Termination. When the energy deficient Balancing Authority is able to meet its Load and Operating Reserve requirements, it shall request its Reliability Coordinator to terminate the EEA.

0.1 Notification. The Reliability Coordinator shall notify all other Reliability Coordinators via the RCIS of the termination. The Reliability Coordinator shall also notify the ~~impacted~~ neighboring Balancing Authorities and Transmission Operators.

Guidelines and Technical Basis

Rationales to be added here after balloting.

Requirement R1:

Requirement R2:

Requirement R3:

Requirement R4:

Requirement R5:

Requirement R6:

Implementation Plan
Project 2009-03 – Emergency Operations

Standards Involved
Approval:
EOP-011-1 — Emergency Operations

Retirements:
- EOP-001-2.1b — Emergency Operations Planning
- EOP-002-3.1 — Capacity and Energy Emergencies
- EOP-003-2— Load Shedding Plans

Prerequisite Approvals
- PRC-010-1 in Project 2008-02 – Undervoltage Load Shedding

Revisions to the NERC Glossary of Terms
The following term is proposed for revision:

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its ~~customers'~~ expected ~~energy~~ Load obligations.

Applicable Entities
Reliability Coordinator
Balancing Authority
Transmission Operator

Conforming Changes to Other Standards
Project 2008-02 – Undervoltage Load Shedding (Requirement 1 of PRC-010): Project 2009-03 - Emergency Operations (EOP-011-1) retires EOP-003-2. Requirements R2, R4 and R7 of EOP-003-2, not being absorbed by EOP-011-1, are mapped to PRC-010-1, Requirement 1.

Effective Date
EOP-011-1 and the definition of "Energy Emergency" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard and definition shall

become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

EOP-011-1 is a consolidation of EOP-001-2.1b – Emergency Operations Planning, EOP-002-3.1 – Capacity and Energy Emergencies and EOP-003-2 – Load Shedding Plans. EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 shall retire at midnight of the day immediately prior to the effective date of EOP-011-1 in the particular jurisdiction in which the new standard is becoming effective.

Implementation Plan
Project 2009-03 – Emergency Operations

Standards Involved
Approval:
EOP-011-1 — Emergency Operations

Retirements:
- EOP-001-2.1b — Emergency Operations Planning
- EOP-002-3.1 — Capacity and Energy Emergencies
- EOP-003-2— Load Shedding Plans

Prerequisite Approvals
- PRC-010-1 in Project 2008-02 – Undervoltage Load Shedding

Revisions to the NERC Glossary of Terms
The following term is proposed for revision:

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer meet its ~~customers'~~ expected ~~energy~~ Load obligations.

Applicable Entities
Reliability Coordinator
Balancing Authority
Transmission Operator

Conforming Changes to Other Standards
Project 2008-02 – Undervoltage Load Shedding (Requirement 1 of PRC-010): Project 2009-03 - Emergency Operations (EOP-011-1) retires EOP-003-2. Requirements R2, R4 and R7 of EOP-003-2, not being absorbed by EOP-011-1, are mapped to PRC-010-1, Requirement 1.

Effective Date
EOP-011-1 and the definition of "Energy Emergency" shall become effective on the first day of the first calendar quarter that is twelve (12) months after the date that the standard and definition are approved by an applicable governmental authority or as otherwise provided for in a jurisdiction where approval by an applicable governmental authority is required for a standard to go into effect. Where approval by an applicable governmental authority is not required, the standard and definition shall

become effective on the first day of the first calendar quarter that is twelve (12) months after the date the standard and definition are adopted by the NERC Board of Trustees or as otherwise provided for in that jurisdiction.

Retirement of Existing Standards:

EOP-011-1 is a consolidation of EOP-001-2.1b – Emergency Operations Planning, EOP-002-3.1 – Capacity and Energy Emergencies and EOP-003-2 – Load Shedding Plans. EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 shall retire at midnight of the day immediately prior to the effective date of EOP-011-1 in the particular jurisdiction in which the new standard is becoming effective.

Summary of Changes EOP-011-1
Project 2009-03 – Emergency Operations

Changes made to proposed EOP-011-1: After careful review, discussion and consideration of comments received by industry stakeholders, the standards drafting team responsible for this project (EOP SDT) made conforming changes to proposed EOP-011-1. The changes drafted in EOP-011-1, through agreement of the EOP SDT on stakeholder comments received, provide additional clarity, consistency and better alignment with the EOP SDT's intent of EOP-011-1.

Throughout the entire proposed standard, where "Operating Plan" was written, the EOP SDT revised "Plan" to read as: "Plan(s)" to indicate that there can be one or multiple Operating Plan(s).

Standard Requirement changes

Requirement R1: "Each Transmission Operator shall develop, maintain, and implement ~~a~~ one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable:"

Requirement R1, Part 1.2.1.: Notification to the Reliability Coordinator…" was changed to: "1.2.1. Notification to its Reliability Coordinator…"

Rationale for R1: The third paragraph in the rationale box for Requirement R1 was revised to read as: "Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency" was retained. This is a process in the plan(s) that determines when the Transmission Operator must notify its Reliability Coordinator."
A fourth paragraph was added to the rationale box to maintain consistency with Requirement R2 rationale box and reads: "An Operating Plan(s) is implemented by carrying out its stated actions."
The fifth paragraph was expanded to provide additional clarity: "If any Parts of Requirement R1 are not applicable, the Transmission Operator should note "not applicable" in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s)."

Requirement R2: "…within its Balancing Authority Area" was added to Requirement R2 and the revision reads as: "Each Balancing Authority shall develop, maintain, and implement ~~a~~ one or more Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable:"

Requirement R2, Part 2.2.1.: "Notification to the Reliability Coordinator…" was revised to read as: "Notification to its Reliability Coordinator…"

Rationale for R2: The fourth paragraph was expanded to provide additional clarity: "If any Parts of Requirement R1 are not applicable, the Balancing Authority should note "not applicable" in the Operating Plan(s). The EOP SDT recognizes that across the regions, Operating Plan(s) may not include all the elements listed in this requirement due to restrictions, other methods of managing situations, and documents that may already exist that speak to a process that already exists. Therefore, the entity must provide in the plan(s) that the element is not applicable and detail why it is not applicable for the plan(s)."

Requirement R3: "…within 30 calendar days of receipt…" was removed from Requirement R3 and added to Requirement R3, Part 3.1.: "…Within 30 calendar days of receipt, the Reliability Coordinator shall:"

Requirement R3, Part 3.1.3.: Revision to Requirement R3, Part 3.1.3. reads as: "Notify each Balancing Authority and Transmission Operator of the results of its review, specifying any time frame for resubmittal of its Operating Plan(s) if revisions are identified."

Rationale for R3: In the last line of the second sentence in the rationale box**,** the word "emergencies" was revised with capitalization of the word "Emergencies," as this is NERC glossary defined term.

Requirement R5 and Measure M5: "…within in Reliability Coordinator Area…" was added to Requirement R5 to read as: "Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area…"

Compliance Section 1.3, Compliance Monitoring and Assessment Processes: Compliance Section 1.3 was revised to read as: "As defined in the NERC Rules of Procedure; "Compliance Monitoring and Assessment Processes" refers to the identification of the processes that will be used to evaluate data or information for the purpose of assessing performance or outcomes with the associated reliability standard."

Table of Compliance Elements: The Table of Compliance Elements was updated to reflect changes made to the Requirements of EOP-011-1.

Attachment 1:

Introduction: In the Introduction section of Attachment 1, the Rationale Box title was added to read as: "Rationale for Introduction." Additionally, in the first sentence in the Rationale for Introduction box, "…as permitted in its transmission tariff…" was added to read as: "…change the priority of a service request as permitted in its transmission tariff…"

2. Notification: The word "adjacent" was changed to "neighboring" to read as: "…shall also notify all neighboring Reliability Coordinators.

2.2 Declaration period: The word "impacted" was changed to "neighboring" to read as: "…and pass this information on to the neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators."

2.3 Sharing information on resource availability: The word "other" was added to read as: "Other Reliability Coordinators of Balancing Authorities…"

2.4 Evaluating and mitigating Transmission limitations: The EOP SDT added "(s)" behind Transmission Operator and added the language "to service" to read as: "The Reliability Coordinator shall review Transmission outages and work with the Transmission Operator(s) to see if it's possible to return to service any Transmission Elements…"

Rationale for EEA 2: A capitalization correction was made from: "Contingency reserves" to "Contingency Reserves."
3.2 Declaration Period: The EOP SDT added the language "energy deficient" and changed the word "impacted" to "neighboring" to read as: "The energy deficient Balancing Authority…" and "…pass this information on to the neighboring Reliability Coordinators, Balancing Authorities, and Transmission Operators."

3.3 Reevaluating and revising SOLs and IROLs: "Transmission Operator" was revised to "Transmission Owner" to read as: "…or as allowed by the Transmission Owner…"

3.4.1. Notification of other parties: The word "impacted" was revised to "neighboring" to read as: "...shall notify neighboring Reliability Coordinators…"

Rationale for EEA 3: A rationale box was added for EEA 3 to provide additional clarity of the EOP SDT's intent of **EEA 3 – Firm Load interruption is imminent or in progress**. The language of the rationale box reads as:

"**Rationale for EEA 3:**

This rationale was added at the request of stakeholders asking for justification for moving a lack of Contingency Reserves into the EEA3 category.

The previous language in EOP-002-3.1, EEA 2 used "Operating Reserve," which is an all-inclusive term, including all reserves (including Contingency Reserves). Many Operating Reserves are used continuously, every hour of every day. Total Operating Reserve requirements are kind of nebulous since they do not have a specific hard minimum value. Contingency Reserves are used far less frequently. Because of the confusion over this issue, evidenced by the comments received, the drafting team thought that using minimum Contingency Reserve in the language would eliminate some of the confusion. This is a different approach but the drafting team believes this is a good approach and was supported by several commenters.

Using Contingency Reserves (which is a subset of Operating Reserves) puts a BA closer to the operating edge. The drafting team felt that the point where a BA can no longer maintain this important Contingency Reserves margin is a most serious condition and puts the BA into a position where they are very close to shedding Load ("imminent or in progress"). The drafting team felt that this warrants categorization at the highest level of EEA."

Alert 0 – Termination:
0.1 Notification: The word "impacted" was changed to "neighboring" to read as: "…also notify the neighboring Balancing Authorities and Transmission Operators."

Project 2009-03: Emergency Operations

VRF and VSL Justifications for EOP-011-1

VRF and VSL Justifications – EOP-011-1, R1	
Proposed VRF	High
NERC VRF Discussion	Developing, maintaining and implementing a Reliability Coordinator-reviewed Operating Plan to provide the Transmission Operator the means to mitigate operating Emergencies in its Transmission Operator Area. This is a requirement that, if violated, could directly cause or contribute to Bulk Electric System (BES) instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. Since this requirement also is in the Operations Planning time frame, it could, if violated, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures; or could hinder restoration to a normal condition. Since this is a Requirement in a planning time frame, a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation or Cascading failures; or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the Operating Plan(s) and is consistent with Requirement R2.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-003-2 R1, which deals with Load shedding under Emergency conditions, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.

VRF and VSL Justifications – EOP-011-1, R1	
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to maintain it.
Proposed High VSL	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to have it reviewed by its Reliability Coordinator.
Proposed Severe VSL	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to implement it.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Operating Plan(s) is not developed, maintained and implemented.

VRF and VSL Justifications – EOP-011-1, R1	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to develop, maintain and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operating Area, failing to have it reviewed by its Reliability Coordinator, or failing to implement it for an Operating emergency.

VRF and VSL Justifications – EOP-011-1, R2	
Proposed VRF	High
NERC VRF Discussion	Developing, maintaining and implementing a Reliability Coordinator-reviewed Operating Plan provides the Balancing Authority the means to mitigate Capacity and Energy Emergencies. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. Since this requirement also is in the Operations Planning time frame, it could, if violated, under emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. Since this is a requirement in a planning time frame, a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the Operating Plan(s) and is consistent with Requirement R1.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-003-2 R1, which deals with Load shedding under Emergency conditions, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.

VRF and VSL Justifications – EOP-011-1, R2	
Proposed Lower VSL	N/A.
Proposed Moderate VSL	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to maintain it.
Proposed High VSL	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to have it reviewed by its Reliability Coordinator.
Proposed Severe VSL	The Balancing Authority failed to develop an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to implement it.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Operating Plan(s) is not developed, maintained and implemented.

VRF and VSL Justifications – EOP-011-1, R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to develop, maintain and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area or failing to have it reviewed by the Reliability Coordinator or failing to implement it for a Capacity or Energy Emergency.

VRF and VSL Justifications – EOP-011-1, R3	
Proposed VRF	Medium
NERC VRF Discussion	Review of an Operating Plan provides the Transmission Operator and Balancing Authority with a Wide Area coordination of their plans. Since this is a requirement in a planning time frame that a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control or restore the BES. However, violation of a medium-risk requirement is unlikely, under Emergency, abnormal or restoration conditions anticipated by the preparations, to lead to BES instability, separation or Cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement specifies that the Reliability Coordinator must review a Transmission Operator's and Balancing Authority's Operating Plans within 30 calendar days of receipt regarding any reliability risks that are identified between Operating Plans. Requirements R1 and R2 specify that the Transmission Operator and Balancing Authority must develop, maintain and implement a Reliability Coordinator-reviewed Operating Plan(s). Requirement R3 ties these three requirements together.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-006-2 R4, which requires the Reliability Coordinator to review neighboring Reliability Coordinator's restoration plans, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

VRF and VSL Justifications – EOP-011-1, R3	
Proposed High VSL	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.
Proposed Severe VSL	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Reliability Coordinator failed to review a Transmission Operator and Balancing Authority Operating Plans that it received regarding any reliability risks that are identified between Operating Plans within the specified time frame.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based	The VSL is assigned for a single instance of failing to review a Transmission Operator and Balancing Authority Operating Plans that it received regarding any reliability risks that are identified between Operating Plans within the specified time frame.

VRF and VSL Justifications – EOP-011-1, R3	
on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – EOP-011-1, R4	
Proposed VRF	High
NERC VRF Discussion	Addressing any reliability risks identified by the Reliability Coordinator during its review Plan provides the Transmission Operator or the Balancing Authority the opportunity to have a Wide-area view of its Operating Plan(s) and to address any risks that it may have overlooked. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. Since this requirement also is in the Operations Planning time frame, it could, if violated, under emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. Since this is a requirement in a planning time frame, a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This requirement specifies that revisions to the Operating Plan(s) be made to address any risks overlooked in the original Operating Plan(s). This requirement is consistent with Requirements R1 and R2 which requires that the Operating Plan(s) be developed, maintained and implemented.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-003-2 R1, which deals with Load shedding under Emergency conditions, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.

VRF and VSL Justifications – EOP-011-1, R4	
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator within the timeframe specified by its Reliability Coordinator.
Proposed Severe VSL	The Transmission Operator or Balancing Authority failed to update and resubmit its Operating Plan(s) to its Reliability Coordinator.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Transmission Operator or Balancing Authority failed to update and resubmit the Operating Plan(s) to its Reliability Coordinator within the timeframe determined by its Reliability Coordinator, or if they simply failed to update and resubmit the Operating Plan(s) to the Reliability Coordinator.
FERC VSL G3	The language of the VSL directly mirrors the language in the corresponding requirement.

VRF and VSL Justifications – EOP-011-1, R4	
Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failure to update and resubmit the Operating Plan(s) to its Reliability Coordinator within the timeframe determined by the Reliability Coordinator, or if they simply failed to update and resubmit the Operating Plan(s) to its Reliability Coordinator.

VRF and VSL Justifications – EOP-011-1, R5	
Proposed VRF	High
NERC VRF Discussion	Notifying Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators of an Emergency helps other entities have proper situational awareness and allows them the opportunity to implement measures to mitigate the Emergency. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement specifies that the Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. This relates to Requirements R1 and R2, whereby the Transmission Operator and the Balancing Authority implement their Operating Plans. These Requirements are all assigned a High VRF.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-011-1 Requirements R1, Part 1.2.1 and Requirement R2, Part 2.2, are assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

VRF and VSL Justifications – EOP-011-1, R5	
Proposed High VSL	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to notify within 30 minutes from the time of receiving notification.
Proposed Severe VSL	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if a Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, within 30 minutes from the time of receiving notification, other neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4	The VSL is assigned for a single instance of failing to notifying other entities within 30 minutes of receiving notification.

VRF and VSL Justifications – EOP-011-1, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – EOP-011-1, R6	
Proposed VRF	High
NERC VRF Discussion	Declaration of a potential or actual Energy Emergency alert helps other entities have proper situational awareness and allows them the opportunity to implement measures to mitigate the Energy Emergency. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement and Attachment 1 provide additional detail regarding the initiation of a potential or actual Energy Emergency. This links to Requirement R2, Part 2.2.2 regarding the criteria for an Energy Emergency alert. Both of these Requirements are assigned a High VRF
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-011-1 Requirement R2, Part 2.2.2, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency alert.

VRF and VSL Justifications – EOP-011-1, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area and fails to declare an NERC Energy Emergency alert, as detailed in Attachment 1.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of a Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area and fails to declare an NERC Energy Emergency alert, as detailed in Attachment 1.

Project 2009-03: Emergency Operations

VRF and VSL Justifications for EOP-011-1

VRF and VSL Justifications – EOP-011-1, R1	
Proposed VRF	High
NERC VRF Discussion	Developing, maintaining and implementing a Reliability Coordinator-reviewed Operating Plan to provide the Transmission Operator the means to mitigate operating Emergencies in its Transmission Operator Area. This is a requirement that, if violated, could directly cause or contribute to Bulk Electric System (BES) instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. Since this requirement also is in the Operations Planning time frame, it could, if violated, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures; or could hinder restoration to a normal condition. Since this is a Requirement in a planning time frame, a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation or Cascading failures; or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the Operating Plan(s) and is consistent with Requirement R2.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-003-2 R1, which deals with Load shedding under Emergency conditions, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.

VRF and VSL Justifications – EOP-011-1, R1	
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to maintain it.
Proposed High VSL	The Transmission Operator developed an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to have it reviewed by ~~the~~ its Reliability Coordinator.
Proposed Severe VSL	The Transmission Operator failed to develop an Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. OR The Transmission Operator developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area but failed to implement it.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Operating Plan(s) is not developed, maintained and implemented.

VRF and VSL Justifications – EOP-011-1, R1	
Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to develop, maintain and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operating Area, failing to have it reviewed by ~~the~~ its Reliability Coordinator, or failing to implement it for an Operating emergency.

VRF and VSL Justifications – EOP-011-1, R2	
Proposed VRF	High
NERC VRF Discussion	Developing, maintaining and implementing a Reliability Coordinator-reviewed Operating Plan provides the Balancing Authority the means to mitigate Capacity and Energy Emergencies. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. Since this requirement also is in the Operations Planning time frame, it could, if violated, under emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. Since this is a requirement in a planning time frame, a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement Parts for this Requirement provide additional detail regarding the Operating Plan(s) and is consistent with Requirement R1.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-003-2 R1, which deals with Load shedding under Emergency conditions, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.

VRF and VSL Justifications – EOP-011-1, R2	
Proposed Lower VSL	N/A~~-~~.
Proposed Moderate VSL	The Balancing Authority developed a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to maintain it.
Proposed High VSL	The Balancing Authority developed an Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to have it reviewed by ~~the~~ its Reliability Coordinator.
Proposed Severe VSL	The Balancing Authority failed to develop an ~~-~~Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area. OR The Balancing Authority developed~~-~~ a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area but failed to implement it.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Operating Plan(s) is not developed, maintained and implemented.

VRF and VSL Justifications – EOP-011-1, R2	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failing to develop, maintain and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies within its Balancing Authority Area or failing to have it reviewed by the Reliability Coordinator or failing to implement it for a Capacity or Energy Emergency.

VRF and VSL Justifications – EOP-011-1, R3	
Proposed VRF	Medium
NERC VRF Discussion	Review of an Operating Plan provides the Transmission Operator and Balancing Authority with a Wide Area coordination of their plans. Since this is a requirement in a planning time frame that a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations, directly and adversely affect the electrical state or capability of the BES, or the ability to effectively monitor, control or restore the BES. However, violation of a medium-risk requirement is unlikely, under Emergency, abnormal or restoration conditions anticipated by the preparations, to lead to BES instability, separation or Cascading failures, nor to hinder restoration to a normal condition. This justifies a Medium VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement specifies that the Reliability Coordinator must review a Transmission Operator's and Balancing Authority's Operating Plans within 30 calendar days of receipt regarding any reliability risks that are identified between Operating Plans. Requirements R1 and R2 specify that the Transmission Operator and Balancing ~~authority~~ Authority must develop, maintain and implement a Reliability Coordinator-reviewed Operating Plan(s). Requirement R3 ties these three requirements together.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-006-2 R4, which requires the Reliability Coordinator to review neighboring Reliability Coordinator's restoration plans, is assigned a Medium VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

VRF and VSL Justifications – EOP-011-1, R3	
Proposed High VSL	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator within 30 calendar days.
Proposed Severe VSL	The Reliability Coordinator identified a reliability risk but failed to notify the Balancing Authority or Transmission Operator
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Reliability Coordinator failed to review a Transmission Operator and Balancing Authority Operating Plans that it received regarding any reliability risks that are identified between Operating Plans within the specified time frame.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based	The VSL is assigned for a single instance of failing to review a Transmission Operator and Balancing Authority- Operating Plans that it received regarding any reliability risks that are identified between Operating Plans within the specified time frame.

VRF and VSL Justifications – EOP-011-1, R3	
on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – EOP-011-1, R4	
Proposed VRF	High
NERC VRF Discussion	Addressing any reliability risks identified by the Reliability Coordinator during its review Plan provides the Transmission Operator or the Balancing Authority the opportunity to have a Wide-area view of its Operating Plan(s) and to address any risks that it may have overlooked. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. Since this requirement also is in the Operations Planning time frame, it could, if violated, under emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures, or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. Since this is a requirement in a planning time frame, a violation could, under Emergency, abnormal or restorative conditions anticipated by the preparations directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or cascading failures; or could hinder restoration to a normal condition. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* This requirement specifies that revisions to the Operating Plan(s) be made to address any risks overlooked in the original Operating Plan(s). This requirement is consistent with Requirements R1 and R2 which requires that the Operating Plan(s) be developed, maintained and implemented.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-003-2 R1, which deals with Load shedding under Emergency conditions, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.

VRF and VSL Justifications – EOP-011-1, R4	
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	The Transmission Operator or Balancing Authority failed to update and resubmit ~~the~~ its Operating Plan(s) to ~~the~~ its Reliability Coordinator within the timeframe specified by ~~the~~ its Reliability Coordinator.
Proposed Severe VSL	The Transmission Operator or Balancing Authority failed to update and resubmit ~~the~~ its Operating Plan(s) to ~~the~~ its Reliability Coordinator.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if the Transmission Operator or Balancing Authority failed to update and resubmit the Operating Plan(s) to ~~the~~ its Reliability Coordinator within the timeframe determined by ~~the~~ its Reliability Coordinator, or if they simply failed to update and resubmit the Operating Plan(s) to the Reliability Coordinator.

VRF and VSL Justifications – EOP-011-1, R4	
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of failure to update and resubmit the Operating Plan(s) to ~~the~~ its Reliability Coordinator within the timeframe determined by the Reliability Coordinator, or if they simply failed to update and resubmit the Operating Plan(s) to ~~the~~ its Reliability Coordinator.

VRF and VSL Justifications – EOP-011-1, R5	
Proposed VRF	High
NERC VRF Discussion	Notifying~~-~~ Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators of an Emergency helps other entities have proper situational awareness and allows them the opportunity to implement measures to mitigate the Emergency. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement specifies that the Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, within 30 minutes from the time of receiving notification, other~~-~~ Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. This relates to Requirements R1 and R2, whereby the Transmission Operator and the Balancing Authority implement their Operating Plans. These Requirements are all assigned a High VRF.
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-011-1 Requirements R1, Part 1.2.1 and Requirement R2, Part 2.2, are assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See "NERC VRF Discussion" above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A

VRF and VSL Justifications – EOP-011-1, R5	
Proposed High VSL	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority did notify ~~other~~ neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators, but failed to~~did not~~ notify within 30 minutes from the time of receiving notification.
Proposed Severe VSL	The Reliability Coordinator that received an Emergency notification from a Transmission Operator or Balancing Authority failed to notify ~~other~~ neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators.
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains unambiguous language that makes clear that the requirement is wholly or partially violated if a Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority shall notify, within 30 minutes from the time of receiving notification, other ~~impacted~~ neighboring Reliability Coordinators, Balancing Authorities and Transmission Operators
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4	The VSL is assigned for a single instance of failing to notifying other entities within 30 minutes of receiving notification.

VRF and VSL Justifications – EOP-011-1, R5	
Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	

VRF and VSL Justifications – EOP-011-1, R6	
Proposed VRF	High
NERC VRF Discussion	Declaration of a potential or actual Energy Emergency alert helps other entities have proper situational awareness and allows them the opportunity to implement measures to mitigate the Energy Emergency. This is a requirement that, if violated, could directly cause or contribute to BES instability, separation or a Cascading sequence of failures; or could place the BES at an unacceptable risk of instability, separation or Cascading failures in Real-time. This justifies a High VRF for this requirement.
FERC VRF G1 Discussion	*Guideline 1- Consistency w/ Blackout Report* This requirement does not address any of the critical areas identified in the Final Blackout Report.
FERC VRF G2 Discussion	*Guideline 2- Consistency within a Reliability Standard* The Requirement and Attachment 1 provide additional detail regarding the initiation of a potential or actual Energy Emergency. This links to Requirement R2, Part 2.2.2 regarding the criteria for an Energy Emergency alert. Both of these Requirements are assigned a High VRF
FERC VRF G3 Discussion	*Guideline 3- Consistency among Reliability Standards* The comparable EOP-011-1 Requirement R2, Part 2.2.2, is assigned a High VRF.
FERC VRF G4 Discussion	*Guideline 4- Consistency with NERC Definitions of VRFs* See “NERC VRF Discussion” above.
FERC VRF G5 Discussion	*Guideline 5- Treatment of Requirements that Co-mingle More than One Obligation* This guideline is not applicable, as the requirement does not co-mingle more than one obligation.
Proposed Lower VSL	N/A
Proposed Moderate VSL	N/A
Proposed High VSL	N/A
Proposed Severe VSL	The Reliability Coordinator that had a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area failed to declare an Energy Emergency alert.

VRF and VSL Justifications – EOP-011-1, R6	
FERC VSL G1 Violation Severity Level Assignments Should Not Have the Unintended Consequence of Lowering the Current Level of Compliance	The VSLs were written to reflect the content of the requirement and do not lower the current levels of compliance.
FERC VSL G2 Violation Severity Level Assignments Should Ensure Uniformity and Consistency in the Determination of Penalties Guideline 2a: The Single Violation Severity Level Assignment Category for "Binary" Requirements Is Not Consistent Guideline 2b: Violation Severity Level Assignments that Contain Ambiguous Language	Guideline 2a: The VSL assignment is not binary. Guideline 2b: The VSL assignment contains clear and unambiguous language that makes clear that the requirement is wholly or partially violated if a Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area and fails to declare an NERC Energy Emergency alert, as detailed in Attachment 1.
FERC VSL G3 Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement	The language of the VSL directly mirrors the language in the corresponding requirement.
FERC VSL G4 Violation Severity Level Assignment Should Be Based on A Single Violation, Not on A Cumulative Number of Violations	The VSL is assigned for a single instance of a Reliability Coordinator that has a Balancing Authority or Load-Serving Entity experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area and fails to declare an NERC Energy Emergency alert, as detailed in Attachment 1.

Project 2009-03 Emergency Operations (EOP-001-2.1b, -002-3.1, and -003-2)

Consideration of Issues and Directives | October 2014

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
P 571 (S- Ref 10066 – EOP-002) "As we stated in the NOPR, neither EOP-002-2 nor any other Reliability Standard addresses the impact of inadequate transmission during generation emergencies. The Commission agrees with MRO that "insufficient transmission capability" could be due to various causes. The ERO should examine whether to clarify this term in the Reliability Standards development process."	FERC Order No. 693	The EOP SDT has included transmission related items to be included in the Transmission Operator's Emergency Operating Plan(s). These items impact transmission capability and include Requirement R1, Parts 1.2.2-1.2.5: 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.4. Transmission system reconfiguration; 1.2.5. Redispatch of generation request;
573 (S- Ref 10067 – EOP-003) "The Commission agrees with FirstEnergy that for demand-side resources to qualify as another tool for balancing authorities to use in meeting control performance and disturbance control Reliability Standards, they must meet comparable technical performance requirements as generation resource options. In response to comments from Comverge and APPA, the Commission believes that curtailable loads are adequately addressed in Requirement R6 of	FERC Order No. 693	The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT developed individual requirements for the Transmission Operator and the Balancing Authority to develop, maintain and implement Operating Plan(s) to mitigate operating Emergencies. The requirements incorporate the applicable elements of Attachment 1 for each entity. **R1.** Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **1.1.** Roles and responsibilities for activating the Operating Plan(s);

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
the Reliability Standard but that demand response is not covered. Demand response covers considerably more resources than interruptible load. Accordingly, the Commission directs the ERO to modify the Reliability Standard to include all technically feasible resource options in the management of emergencies. These options should include generation resources, demand response resources and other technologies that meet comparable technical performance requirements."		**1.2.** Processes to prepare for and mitigate Emergencies including: **1.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; **1.2.2.** Cancellation or recall of Transmission and generation outages; **1.2.3.** Transmission system reconfiguration; **1.2.4.** Redispatch of generation request; **1.2.5.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **1.2.6.** Reliability impacts of extreme weather conditions. **R2.** Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **2.1.** Roles and responsibilities for activating the Operating Plan(s); **2.2.** Processes to prepare for and mitigate Emergencies including: **2.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; **2.2.2.** Requesting an Energy Emergency Alert, per Attachment 1;

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		2.2.3. Managing generating resources in its Balancing Authority Area to address: **2.2.3.1.** capability and availability; **2.2.3.2.** fuel supply and inventory concerns; **2.2.3.3.** fuel switching capabilities; and **2.2.3.4.** environmental constraints. **2.2.4.** Public appeals for voluntary Load reductions; **2.2.5.** Requests to government agencies to implement their programs to achieve necessary energy reductions; **2.2.6.** Reduction of internal utility energy use; **2.2.7.** Use of Interruptible Load, curtailable Load and demand response; **2.2.8.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **2.2.9.** Reliability impacts of extreme weather conditions.
595 (S- Ref 10072 – EOP-003) "The Commission concludes that the Reliability Standard needs to be modified to ensure that adequate load shedding capabilities are provided so that system	FERC Order No. 693	The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT developed individual requirements for the Transmission Operator and the Balancing Authority to develop, maintain and implement Operating Plan(s) to mitigate operating Emergencies. The requirements incorporate the applicable elements of Attachment 1 for each entity.

NERC

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
operators have an effective operating measure of last resort to contain system emergencies and prevent cascading. The Commission recognizes that the amount of load shedding capability required is dependent on system characteristics and therefore it may not be feasible to have a uniform nationwide load shedding capability. This, however, does not preclude a uniform nationwide criterion on the methodology for establishing load shedding capability that would specify the minimum amount of load shedding capability that should be provided based on system characteristics and conditions and the maximum amount of delay before load shedding can be implemented. The Commission directs the ERO to address the minimum load and maximum time concerns of the Commission through the Reliability Standards development process. We suggest that a review of industry best practices would be useful in developing nationwide critera.		**R1.** Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **1.1.** Roles and responsibilities for activating the Operating Plan(s); **1.2.** Processes to prepare for and mitigate Emergencies including: **1.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; **1.2.2.** Cancellation or recall of Transmission and generation outages; **1.2.3.** Transmission system reconfiguration; **1.2.4.** Redispatch of generation request; **1.2.5.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **1.2.6.** Reliability impacts of extreme weather conditions. **R2.** Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]*

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
		2.1. Roles and responsibilities for activating the Operating Plan(s); **2.2.** Processes to prepare for and mitigate Emergencies including: **2.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; **2.2.2.** Requesting an Energy Emergency Alert, per Attachment 1; **2.2.3.** Managing generating resources in its Balancing Authority Area to address: **2.2.3.1.** capability and availability; **2.2.3.2.** fuel supply and inventory concerns; **2.2.3.3.** fuel switching capabilities; and **2.2.3.4.** environmental constraints. **2.2.4.** Public appeals for voluntary Load reductions; **2.2.5.** Requests to government agencies to implement their programs to achieve necessary energy reductions; **2.2.6.** Reduction of internal utility energy use; **2.2.7.** Use of Interruptible Load, curtailable Load and demand response; **2.2.8.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **2.2.9.** Reliability impacts of extreme weather conditions.

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
P 597 (S- Ref 10073 – EOP-003) “As suggested by California PUC, periodic drills of simulated load shedding should involve all participants required to ensure successful implementation of load shedding plans. As such, the drills should extend beyond system operators to distribution operators and LSEs. The Reliability Standard should require periodic drills by entities subject to section 215, and require those entities to seek participation by other entities. The drills should test the readiness and functionality of the load shedding plans, including, at times, the actual deployment of personnel. Therefore the Commission disagrees with FirstEnergy that the requirement for periodic drills of simulated load shedding should be incorporated into the new PER-005-0 Reliability Standard that is currently being drafted to address operator training.”	FERC Order No. 693	The Transmission Operator participates in Reliability Coordinator restoration drills and they will be able to shed Load with or without the Load-Serving Entity or Distribution Provider. Transmission Operators also participate in annual training required under Reliability Standard PER-005-2. NERC has launched the Risk-Based Registration (RBR) Initiative to ensure that the right entities are subject to the right set of applicable Reliability Standards, using a consistent approach to risk assessment and registration across the ERO. The goal is to develop enhanced registry criteria, including the use of thresholds and specific Reliability Standards applicability, where appropriate, to better align compliance obligations with material risk to Bulk Electric System reliability. The proposed enhancements reduce unnecessary burdens by all involved while preserving Bulk Electric System reliability and avoiding causing or exacerbating instability, uncontrolled separation, or Cascading failures.
P 601 (S- Ref 10074 – EOP-003) “APPA Comments are in Paragraph 598: ‘In addition, APPA states that NERC should consider requiring balancing authorities and	FERC Order No. 693	The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT developed individual requirements for the Transmission Operator and the Balancing Authority to develop, maintain and implement Operating Plan(s) to mitigate operating Emergencies. The requirements incorporate the applicable elements of Attachment 1 for each entity.

Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners'."		Coordination and planning of automatic and manual Load shedding has been adequately addressed by requiring Transmission Operators and Balancing Authorities to have a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies. **R1.** Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **1.1.** Roles and responsibilities for activating the Operating Plan(s); **1.2.** Processes to prepare for and mitigate Emergencies including: **1.2.1.** Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; **1.2.2.** Cancellation or recall of Transmission and generation outages; **1.2.3.** Transmission system reconfiguration; **1.2.4.** Redispatch of generation request; **1.2.5.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **1.2.6.** Reliability impacts of extreme weather conditions. **R2.** Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan(s) shall include the following, as

Project 2009-03 Emergency Operations		
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Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
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NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Project 2009-03 Emergency Operations (EOP-001-2.1b, -002-3.1, and -003-2)

Consideration of Issues and Directives | ~~July~~ October 2014

Project 2009-03 Emergency Operations		
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Project 2009-03 Emergency Operations		
Issue or Directive	**Source**	**Consideration of Issue or Directive**
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transmission operators to expand coordination and planning of their automatic and manual load shedding plans to include their respective Regional Entities, reliability coordinators and generation owners'."		Coordination and planning of automatic and manual Load shedding has been adequately addressed by requiring Transmission Operators and Balancing Authorities to have a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies. **R1.** Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning]* **1.1.** Roles and responsibilities for activating the Operating Plan(s); **1.2.** Processes to prepare for and mitigate Emergencies including: **1.2.1.** Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; **1.2.2.** Cancellation or recall of Transmission and generation outages; **1.2.3.** Transmission system reconfiguration; **1.2.4.** Redispatch of generation request; **1.2.5.** Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and **1.2.6.** Reliability impacts of extreme weather conditions. **R2.** Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies. The Operating Plan(s) shall include the following, as

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Project 2009-03 Emergency Operations		
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		capable of being implemented in a timeframe adequate for mitigating the Emergency; and **2.2.9.** Reliability impacts of extreme weather conditions.

Proposed Definitions for the NERC Glossary of Terms

Project 2009-03: Emergency Operations

The Emergency Operations Standards Drafting Team (EOP SDT) proposes revisions to a defined term in the NERC Glossary of Terms. This defined term is used in the EOP family of standards and in other standards or defined terms as discussed below.

Proposed revised definitions (redlined):

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer ~~provide~~ meet its ~~customers'~~ expected ~~energy~~ Load ~~requirements~~ obligations.

This defined term was revised to provide clarity that an Energy Emergency is not necessarily limited to a Load-Serving Entity.

This defined term, or variations of it, is also used in the instances below. The EOP SDT does not believe that the proposed revisions change the reliability intent of these standard or definitions.

- **BAL-002-WECC – Contingency Reserve**: This standard becomes enforceable on October 1st, 2014. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **IRO-005-3.1a — Reliability Coordination — Current Day Operations** - This standard was revised under Project 2006-06 and the reference to Energy Emergency was removed from the standard. The standard was approved by the NERC BOT and filed with FERC. NERC has requested that FERC defer action on its petition and is revising this standard under project 2014-03, TOP / IRO Revisions. This project is scheduled to be completed no later than January 31, 2015. The two standard drafting teams are coordinating the definition revision to ensure there are no redundancies.
- **MOD-004-1 — Capacity Benefit Margin:** This standard is being retired and replaced with MOD-001-2 — Modeling, Data, and Analysis — Available Transmission System Capability (NERC BOT approved February 6, 2014). The term "energy emergency" is not used in the new standard. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability to the existing approved standard.
- **INT-004-3 – Dynamic Transfers:** This standard was a revision to INT-004-2 under Project 2008-12. INT-004-3 was approved by the NERC BOT and filed with FERC. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.

- **Defined term Emergency Request for Interchange:** This term is not used in any existing approved standard.

Project 2009-03 - Emergency Operations

Mapping Document

Project Purpose

The Emergency Operations Five-Year Review Team (EOP FYRT) was appointed by the Standards Committee Executive Committee on April 22, 2013. The EOP FYRT has reviewed the following Emergency Operations standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 to decide if revisions are needed in the scope of this project in relation to P81 and FERC directives. This project is a comprehensive review of this set of EOP standards to ensure that the requirements are clear and unambiguous. Many of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process, and the standards were due for a comprehensive review. Suggestions for improvement, possible consolidation and for requirements to be considered for retirement under Paragraph 81 have been submitted by stakeholders, other drafting teams and FERC staff.

On October 17, 2013 the Standards Committee accepted the recommendations of the EOP FYRT and appointed a drafting team to implement the recommendations and begin formal development. The Standards Committee further authorized the posting of the Standard Authorization Request (SAR) developed by the EOP FYRT.

Project 2009-03 – Emergency Operations (EOP-011-1) is being coordinated with Project 2008-02 – Undervoltage Load Shedding, which proposes to retire EOP-003-2 Requirements R2, R4, and R7 since these requirements are proposed to be covered by PRC-010-1, Requirement R1; this translation is illustrated in this document and will also be referenced in Project 2008-02's mapping document. The project schedules and implementation plans for these two projects are being closely coordinated to ensure that no gaps or duplication will result from the products developed by the two drafting teams.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.9. Reliability impacts of extreme weather conditions.
R2. Each Transmission Operator and Balancing Authority shall: **R2.1.** Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity. **R2.2.** Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system. **R2.3.** Develop, maintain, and implement a set of plans for load shedding	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s);

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include: **R3.1.** Communications protocols to be used during emergencies.	Translated to EOP-011-1, Emergency Operations; Retired R3.1 under Criteria A and B7 of Paragraph 81 guidelines; Retired	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R3.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions. **R3.3.** The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities. **R3.4.** Staffing levels for the emergency.	R3.4 under Criteria A and B1 of Paragraph 81 guidelines.	Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		EOP-011-1, R2 R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		<u>**Retirements:**</u> **Requirement R3.1** • Meets Criterion B7 and Criterion A of Paragraph 81; • Covered by EOP-001-2.1b Requirement R4 in Attachment 1 (proposed Requirements R1 and R2 in EOP-011-1); and • COM-001 and COM-002 are descriptive in the identification of protocols to use and, thus, adequately cover the generic reference. **Requirement R3.2** • Meets Criterion B7 and Criterion A of Paragraph 81; and • Load reduction within timelines is covered by BAL-002 Requirement R2. **Requirement R3.4** • Meets Criterion B1 of Paragraph 81; and • Staffing levels are administrative in nature.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to the Reliability Coordinator within a time period specified by its Reliability Coordinator. [Violation Risk Factor: High] [Time Horizon: Operation Planning]
R6. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable: **R6.1.** The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems. **R6.2.** The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency capacity or energy transfers if existing agreements cannot be used. **R6.3.** The Transmission Operator and Balancing Authority shall coordinate transmission	Retired under Criteria B6 and B7 of P81 guidelines.	**<u>Retirements</u>** **Requirement R6.1** • Meets Criterion B7 of Paragraph 81; and • Redundant with COM-001. **Requirement R6.2** • Meets Criterion B6 of Paragraph 81; • Speaks to an action to be taken during capacity issues that is not feasible in accomplishing; and • Transaction arrangements are a commercial practice. **Requirement R6.3** • Meets Criterion B7 of Paragraph 81; and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.) **R6.4.** The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.		• Covered by EOP-001-2.1b Requirement R4 in Attachment 1 (proposed Requirements R1 and R2 in EOP-011-1). **Requirement R6.4** • Meets Criterion A of Paragraph 81; and • Does not provide benefit to the reliability of the BES.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall	Retired under Criteria A and B7 of P81 guidelines.	**Retired – redundant with PER-001, R1 with respect to the Balancing Authority and IRO-001-1.1, Requirement R3 for the Reliability Coordinator.**

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
exercise specific authority to alleviate capacity and energy emergencies.		
R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan to reduce risks to the interconnected system.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators. *[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]*
		EOP-011-1, R2

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.	Translated to EOP-011-1, Emergency Operations.	R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: **R6.1.** Loading all available generating capacity. **R6.2.** Deploying all available operating reserve. **R6.3.** Interrupting interruptible load and exports. **R6.4.** Requesting emergency assistance from other Balancing Authorities. **R6.5.** Declaring an Energy Emergency through its Reliability Coordinator; and **R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing Authority shall: **R7.1.** Manually shed firm load without delay to return its ACE to zero; and **R7.2.** Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R6** R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration transmission Service from designated Network Resources) as permitted in its transmission tariff: **R9.1**. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts." **R9.2.** The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed. **R9.3.** The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.	Retired per P81 – this is addressed in NAESB tagging specification.	**LSEs have no Real-time reliability functionality with respect to EEAs.** Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R9.4. The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.		
Attachment 1 **2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.	Translated to EOP-011-1, Attachment 1.	**Attachment 1EEA 2 – Load management procedures in effect** • An energy deficient BA is still able to maintain minimum Contingency Reserve requirements.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.		reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.	EOP-003-2, R2 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design.	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.1. The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design. **1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding plans, among other interconnected Transmission Operators and Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		EOP-011-1, R2 R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.9. Reliability impacts of extreme weather conditions.
R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels.	EOP-003-2, R4 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design. EOP-003-2, R4 is inherently embedded in PRC-010-1, R1, Part 1.1. The specific items noted are described in PRC-010-1's	**Proposed Language in PRC-010-1**[LA1]**:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
	Guidelines and Technical Basis.	**1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.	Retired under Criteria A and B7 of Paragraph 81.	**Redundant with R1 of EOP-003-2, which maps to EOP-011-1, R1.** Requirement R5 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.	Retired under Criteria and B7 of Paragraph 81.	**Redundant with R1 of EOP-003-2, which maps to EOP-011-1, R1.** Requirement R6 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R6 speaks of two events that must be valid to tell the BA or TOP to shed more Load. .
R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions.	EOP-003-2, R7 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design. EOP-003-2, R7 is inherently embedded in PRC-010-1, R1, Part 1.2.	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]* **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
	The specific items noted are described in PRC-010-1's Guidelines and Technical Basis.	**1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		EOP-011-1, R2 R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**

Project 2009-03 - Emergency Operations

Mapping Document

Project Purpose

The Emergency Operations Five-Year Review Team (EOP FYRT) was appointed by the Standards Committee Executive Committee on April 22, 2013. The EOP FYRT has reviewed the following Emergency Operations standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 to decide if revisions are needed in the scope of this project in relation to P81 and FERC directives. This project is a comprehensive review of this set of EOP standards to ensure that the requirements are clear and unambiguous. Many of the requirements in this set of standards were translated from Operating Policies as part of the Version 0 process, and the standards were due for a comprehensive review. Suggestions for improvement, possible consolidation and for requirements to be considered for retirement under Paragraph 81 have been submitted by stakeholders, other drafting teams and FERC staff.

On October 17, 2013 the Standards Committee accepted the recommendations of the EOP FYRT and appointed a drafting team to implement the recommendations and begin formal development. The Standards Committee further authorized the posting of the Standard Authorization Request (SAR) developed by the EOP FYRT.

Project 2009-03 – Emergency Operations (EOP-011-1) is being coordinated with Project 2008-02 – Undervoltage Load Shedding, which proposes to retire EOP-003-2 Requirements R2, R4, and R7 since these requirements are proposed to be covered by PRC-010-1, Requirement R1; this translation is illustrated in this document and will also be referenced in Project 2008-02's mapping document. The project schedules and implementation plans for these two projects are being closely coordinated to ensure that no gaps or duplication will result from the products developed by the two drafting teams.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Balancing Authorities shall have operating agreements with adjacent Balancing Authorities that shall, at a minimum, contain provisions for emergency assistance, including provisions to obtain emergency assistance from remote Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate ~~operating~~ Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. ~~in its Transmission Operator Area.~~ The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.9. Reliability impacts of extreme weather conditions.
R2. Each Transmission Operator and Balancing Authority shall: **R2.1.** Develop, maintain, and implement a set of plans to mitigate operating emergencies for insufficient generating capacity. **R2.2.** Develop, maintain, and implement a set of plans to mitigate operating emergencies on the transmission system. **R2.3.** Develop, maintain, and implement a set of plans for load shedding	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission ~~-~~Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s);

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R3. Each Transmission Operator and Balancing Authority shall have emergency plans that will enable it to mitigate operating emergencies. At a minimum, Transmission Operator and Balancing Authority emergency plans shall include: **R3.1.** Communications protocols to be used during emergencies.	Translated to EOP-011-1, Emergency Operations; Retired R3.1 under Criteria A and B7 of Paragraph 81 guidelines; Retired	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission- Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R3.2. A list of controlling actions to resolve the emergency. Load reduction, in sufficient quantity to resolve the emergency within NERC-established timelines, shall be one of the controlling actions. **R3.3.** The tasks to be coordinated with and among adjacent Transmission Operators and Balancing Authorities. **R3.4.** Staffing levels for the emergency.	R3.4 under Criteria A and B1 of Paragraph 81 guidelines.	Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		EOP-011-1, R2 R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Retirements: **Requirement R3.1** • Meets Criterion B7 and Criterion A of Paragraph 81; • Covered by EOP-001-2.1b Requirement R4 in Attachment 1 (proposed Requirements R1 and R2 in EOP-011-1); and • COM-001 and COM-002 are descriptive in the identification of protocols to use and, thus, adequately cover the generic reference. **Requirement R3.2** • Meets Criterion B7 and Criterion A of Paragraph 81; and • Load reduction within timelines is covered by BAL-002 Requirement R2. **Requirement R3.4** • Meets Criterion B1 of Paragraph 81; and • Staffing levels are administrative in nature.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R4. Each Transmission Operator and Balancing Authority shall include the applicable elements in Attachment 1-EOP-001 when developing an emergency plan.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission -Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response;

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R5. The Transmission Operator and Balancing Authority shall annually review and update each emergency plan. The Transmission Operator and Balancing Authority shall provide a copy of its updated emergency plans to its Reliability Coordinator and to neighboring Transmission Operators and Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission -Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s);

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		R4. Each Transmission Operator and Balancing Authority shall address any reliability risks identified by its Reliability Coordinator pursuant to Requirement R3 and resubmit its Operating Plan(s) to the Reliability Coordinator within a time period specified by its Reliability Coordinator. [Violation Risk Factor: High] [Time Horizon: Operation Planning]
R6. The Transmission Operator and Balancing Authority shall coordinate its emergency plans with other Transmission Operators and Balancing Authorities as appropriate. This coordination includes the following steps, as applicable: **R6.1.** The Transmission Operator and Balancing Authority shall establish and maintain reliable communications between interconnected systems. **R6.2.** The Transmission Operator and Balancing Authority shall arrange new interchange agreements to provide for emergency	Retired under Criteria B6 and B7 of P81 guidelines.	**<u>Retirements</u>** **Requirement R6.1** • Meets Criterion B7 of Paragraph 81; and • Redundant with COM-001. **Requirement R6.2** • Meets Criterion B6 of Paragraph 81; • Speaks to an action to be taken during capacity issues that is not feasible in accomplishing; and • Transaction arrangements are a commercial practice. **Requirement R6.3**

Standard: EOP-001-2.1b, Emergency Operations Planning		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
capacity or energy transfers if existing agreements cannot be used. **R6.3.** The Transmission Operator and Balancing Authority shall coordinate transmission and generator maintenance schedules to maximize capacity or conserve the fuel in short supply. (This includes water for hydro generators.) **R6.4.** The Transmission Operator and Balancing Authority shall arrange deliveries of electrical energy or fuel from remote systems through normal operating channels.		• Meets Criterion B7 of Paragraph 81; and • Covered by EOP-001-2.1b Requirement R4 in Attachment 1 (proposed Requirements R1 and R2 in EOP-011-1). **Requirement R6.4** • Meets Criterion A of Paragraph 81; and • Does not provide benefit to the reliability of the BES.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. Each Balancing Authority and Reliability Coordinator shall have the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies.	Retired under Criteria A and B7 of P81 guidelines.	**Retired – redundant with PER-001, R1 with respect to the Balancing Authority and IRO-001-1.1, Requirement R3 for the Reliability Coordinator.**
R2. Each Balancing Authority shall, when required and as appropriate, take one or more actions as described in its capacity and energy emergency plan to reduce risks to the interconnected system.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R3. A Balancing Authority that is experiencing an operating capacity or energy emergency shall communicate its current and future system conditions to its Reliability Coordinator and neighboring Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s);

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions. R5. Each Reliability Coordinator that receives an Emergency notification from a Transmission Operator or Balancing Authority within its Reliability Coordinator Area shall notify, within 30 minutes from the time of receiving notification, other Balancing Authorities and Transmission Operators in its Reliability Coordinator Area, and neighboring Reliability Coordinators.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		[Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
R4. A Balancing Authority anticipating an operating capacity or energy emergency shall perform all actions necessary including bringing on all available generation, postponing equipment maintenance, scheduling interchange purchases in advance, and being prepared to reduce firm load.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R5. A deficient Balancing Authority shall only use the assistance provided by the Interconnection's frequency bias for the time needed to implement corrective actions. The Balancing Authority shall not unilaterally adjust generation in an attempt to return interconnection frequency to normal beyond that supplied through frequency bias action and Interchange Schedule changes. Such unilateral adjustment may overload transmission facilities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including:

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R6. If the Balancing Authority cannot comply with the Control Performance and Disturbance Control Standards, then it shall immediately implement remedies to do so. These remedies include, but are not limited to: **R6.1.** Loading all available generating capacity. **R6.2.** Deploying all available operating reserve. **R6.3.** Interrupting interruptible load and exports. **R6.4.** Requesting emergency assistance from other Balancing Authorities.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning]

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R6.5. Declaring an Energy Emergency through its Reliability Coordinator; and **R6.6.** Reducing load, through procedures such as public appeals, voltage reductions, curtailing interruptible loads and firm loads.		2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions;

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R7. Once the Balancing Authority has exhausted the steps listed in Requirement 6, or if these steps cannot be completed in sufficient time to resolve the emergency condition, the Balancing	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Authority shall: **R7.1.** Manually shed firm load without delay to return its ACE to zero; and **R7.2.** Request the Reliability Coordinator to declare an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."		Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R8. A Reliability Coordinator that has any Balancing Authority within its Reliability Coordinator area experiencing a potential or actual Energy Emergency shall initiate an Energy Emergency Alert as detailed in Attachment 1-EOP-002 "Energy Emergency Alerts." The Reliability Coordinator shall act to mitigate the emergency condition, including a request for emergency assistance if required.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R6** R6. Each Reliability Coordinator that has a Balancing Authority experiencing a potential or actual Energy Emergency within its Reliability Coordinator Area shall declare an Energy Emergency Alert, as detailed in Attachment 1. [Violation Risk Factor: High] [Time Horizon: Real-Time Operations]
R9. When a Transmission Service Provider expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration transmission Service from designated Network Resources) as permitted in its transmission tariff: **R9.1**. The deficient Load-Serving Entity shall request its Reliability Coordinator to initiate an Energy Emergency Alert in accordance with Attachment 1-EOP-002 "Energy Emergency Alerts."	Retired per P81 – this is addressed in NAESB tagging specification.	**LSEs have no Real-time reliability functionality with respect to EEAs.** Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR; and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of

Standard: EOP-002-3.1, Capacity and Energy Emergencies		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R9.2. The Reliability Coordinator shall submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed. **R9.3.** The Reliability Coordinator shall use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7. **R9.4.** The Reliability Coordinator shall use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7.		Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired.
Attachment 1 **2.6.4 Operating Reserves.** Operating reserves are being utilized such that the Energy Deficient Entity is carrying reserves below the required minimum or has initiated emergency assistance through its operating reserve sharing program.	Translated to EOP-011-1, Attachment 1.	**Attachment 1EEA 2 – Load management procedures in effect** • An energy deficient BA is still able to maintain minimum Contingency Reserve requirements.

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
R1. After taking all other remedial steps, a Transmission Operator or Balancing Authority operating with insufficient generation or transmission capacity shall shed customer load rather than risk an uncontrolled failure of components or cascading outages of the Interconnection.	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission- Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s);

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R2. Each Transmission Operator shall establish plans for automatic load shedding for undervoltage conditions if the Transmission Operator or its associated Transmission Planner(s) or Planning Coordinator(s) determine that an under-voltage load shedding scheme is required.	EOP-003-2, R2 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term*

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
	responsible for the program design.	*Planning]* **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design. **1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R3. Each Transmission Operator and Balancing Authority shall coordinate load shedding plans, excluding automatic under-frequency load shedding	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
plans, among other interconnected Transmission Operators and Balancing Authorities.		reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission~~-~~ Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		when experiencing a Capacity Emergency or Energy Emergency; 2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.
R4. A Transmission Operator shall consider one or more of these factors in designing an automatic under voltage load shedding scheme: voltage level, rate of voltage decay, or power flow levels.	EOP-003-2, R4 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design. EOP-003-2, R4 is inherently embedded in PRC-	**Proposed Language in PRC-010-1**[LA1]**:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term Planning]*

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
	010-1, R1, Part 1.1. The specific items noted are described in PRC-010-1's Guidelines and Technical Basis.	**1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design. **1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R5. A Transmission Operator or Balancing Authority shall implement load shedding, excluding automatic under-frequency load shedding, in steps established to minimize the risk of further uncontrolled separation, loss of generation, or system shutdown.	Retired under Criteria A and B7 of Paragraph 81.	**Redundant with R1 of EOP-003-2, which maps to EOP-011-1, R1.**

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		Requirement R5 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement.
R6. After a Transmission Operator or Balancing Authority Area separates from the Interconnection, if there is insufficient generating capacity to restore system frequency following automatic underfrequency load shedding, the Transmission Operator or Balancing Authority shall shed additional load.	Retired under Criteria and B7 of Paragraph 81.	**Redundant with R1 of EOP-003-2, which maps to EOP-011-1, R1.** Requirement R6 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R6 speaks of two events that must be valid to tell the BA or TOP to shed more Load. .
R7. The Transmission Operator shall coordinate automatic undervoltage load shedding throughout their areas with tripping of shunt capacitors, and other automatic actions that will occur under abnormal voltage, or power flow conditions.	EOP-003-2, R7 maps to PRC-010-1, R1. Applicability is changed to the PC or TP because the PC or TP is responsible for the program design.	**Proposed Language in PRC-010-1:** **R1.** Each Planning Coordinator or Transmission Planner that is developing a UVLS Program shall evaluate its effectiveness and subsequently provide the UVLS Program's specifications and implementation schedule to the UVLS entities responsible for implementing the UVLS program. The evaluation shall include, but is not limited to, studies and analyses that show: *[Violation Risk Factor: High] [Time Horizon: Long-term*

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
	EOP-003-2, R7 is inherently embedded in PRC-010-1, R1, Part 1.2. The specific items noted are described in PRC-010-1's Guidelines and Technical Basis.	*Planning]* **1.1.** The implementation of the UVLS Program resolves the identified undervoltage issues that led to its development and design. **1.2.** The UVLS Program is integrated through coordination with generator voltage ride-through capabilities and other protection and control systems, including, but not limited to, transmission line protection, autoreclosing, Remedial Action Schemes, and other undervoltage-based load shedding programs. These tasks need to be performed in a planning horizon in order to be implemented before any operational issues arise. EOP-011-1 relates to Real-time operations and the operations planning time horizon.
R8. Each Transmission Operator or Balancing Authority shall have plans for operator controlled manual load shedding to respond to real-time emergencies. The	Translated to EOP-011-1, Emergency Operations.	**EOP-011-1, R1** R1. Each Transmission Operator shall develop, maintain, and implement a Reliability Coordinator-

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
Transmission Operator or Balancing Authority shall be capable of implementing the load shedding in a timeframe adequate for responding to the emergency.		reviewed Operating Plan(s) to mitigate operating Emergencies in its Transmission~~-~~ Operator Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 1.1. Roles and responsibilities for activating the Operating Plan(s); 1.2. Processes to prepare for and mitigate Emergencies including: 1.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions, when experiencing an operating Emergency; 1.2.2. Cancellation or recall of Transmission and generation outages; 1.2.3. Transmission system reconfiguration; 1.2.4. Redispatch of generation request; 1.2.5. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a timeframe adequate for mitigating the Emergency; and

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		1.2.6. Reliability impacts of extreme weather conditions; and **EOP-011-1, R2** R2. Each Balancing Authority shall develop, maintain, and implement a Reliability Coordinator-reviewed Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area. The Operating Plan(s) shall include the following, as applicable: [Violation Risk Factor: High] [Time Horizon: Real-Time Operations, Operations Planning, Long-term Planning] 2.1. Roles and responsibilities for activating the Operating Plan(s); 2.2. Processes to prepare for and mitigate Emergencies including: 2.2.1. Notification to ~~the~~ its Reliability Coordinator, to include current and projected conditions when experiencing a Capacity Emergency or Energy Emergency;

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		2.2.2 Requesting an Energy Emergency Alert, per Attachment 1; 2.2.3. Managing generating resources in its Balancing Authority Area to address: 2.2.3.1. capability and availability; 2.2.3.2. fuel supply and inventory concerns; 2.2.3.3. fuel switching capabilities; and 2.2.3.4. environmental constraints. 2.2.4. Public appeals for voluntary Load reductions; 2.2.5. Requests to government agencies to implement their programs to achieve necessary energy reductions; 2.2.6. Reduction of internal utility energy use; 2.2.7. Use of Interruptible Load, curtailable Load and demand response; 2.2.8. Provisions for operator-controlled manual Load shedding that minimizes the overlap with automatic Load shedding and are capable of being implemented in a

Standard: EOP-003-2, Load Shedding Plans		
Requirement in Approved Standard	**Translation to New Standard or Other Action**	**Comments**
		timeframe adequate for mitigating the Emergency; and 2.2.9. Reliability impacts of extreme weather conditions.

Technical Justification
EOP-011-1 Emergency Operations and Planning

Background and Rationale for revisions of EOP-001-2.1b, EOP-002-3.1 and EOP-003-2

Purpose

The purpose of EOP-011-1 is to address the effects of operating Emergencies by ensuring each Transmission Operator and Balancing Authority has developed Operating Plan(s) to mitigate operating Emergencies, and that those plans are coordinated within a Reliability Coordinator Area. The standard streamlines the requirements for Emergency Operations for the BES into a clearer and more concise standard that is organized by Functional Entity in order to eliminate the ambiguity in previous versions. In addition, the revisions clarify the critical requirements for Emergency Operations, while ensuring strong communication and coordination across the Functional Entities.

The requirements of the proposed EOP-011-1 reliability standard support the following Reliability Principles:

> Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
>
> The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
>
> Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.
>
> Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

EOP-011-1 consolidates requirements from three existing Emergency Operations standards: EOP-001-2.1b, EOP-002-3.1 and EOP-003-2. The table *Elements for Consideration in Development of Emergency Plans* from Attachment 1 of EOP-001-2.1b were considered by the EOP SDT and incorporated into the requirements of proposed EOP-011-1.

The Project 2009-03 Emergency Operations Standard Drafting Team (EOP SDT) developed EOP-011-1 by considering the following inputs:

- Applicable FERC directives; and
- Five Year Review Team (FYRT) recommendations and considerations of:
  - Independent Expert Review Panel recommendations; and
  - Paragraph 81 criteria.

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History and Inputs to Project 2009-03 Emergency Operations

Periodic Review of EOP Standards

The North American Electric Reliability Corporation (NERC) is required to conduct a periodic review of each NERC Reliability Standard at least once every 10 years, or once every five years for any Reliability Standard approved by the American National Standards Institute as an American National Standard.[1] The Emergency Operations Five-Year Review Team (EOP FYRT) was appointed by the Standards Committee Executive Committee on April 22, 2013. The EOP FYRT reviewed the following Emergency Operations standards: EOP-001-2.1b (Emergency Operations Planning), EOP-002-3.1 (Capacity and Energy Emergencies) and EOP-003-2 (Load Shedding Plans) to determine if the standards should be retained, retired or if revisions were needed in the scope of this project in relation to P81 criteria, Independent Expert report and FERC directives.

The scope of the review included consideration of recommendations from the Industry Expert Review Panel report, Paragraph 81 recommendations and criteria, and outstanding FERC Order No. 693 directives, as well as industry comments. The EOP FYRT posted its draft recommendations to revise the standards for stakeholder comment. After reviewing stakeholder comments, the EOP FYRT submitted its final recommendations to the Standards Committee, along with a Standard Authorization Request (SAR). This SAR replaces an earlier SAR, and the new SAR provided the scope for the work of Project 2009-03. The EOP SDT implemented the FYRT recommendations into proposed reliability standard EOP-011-1.

Industry Expert Report2

In 2013 NERC assembled a panel of Industry Experts (the IERP) to review all reliability standards and provide recommendations for consideration in the transition of NERC standards to steady state. For the Emergency Operations and Planning reliability standards, the Industry Experts made the following recommendations:

- EOP-001-2.1b, R6 - P81. Duplicative of R4 and the Attachment
- EOP-002-3.1, R2 - P81. Duplicative - requirement to take action is in R1.
- EOP-002-3.1, R3 - P81. Duplicative of what is required to be in the plan under Attachment 1 of EOP-001.
- EOP-002-3.1, R6 -P81. Duplicative of BAL standards to meet CPS and DCS
- EOP-002-3.1, R9 - P81. This is a market (tariff) issue.
- EOP-003-2, R2 - P81. Duplicative of PRC-010 and TPL standards
- EOP-003-2, R4 - P81. Duplicative of PRC-010 and TPL standards

[1] NERC Standard Processes Manual 45 (2013), posted at http://www.nerc.com/pa/Stand/Documents/Appendix_3A_StandardsProcessesManual.pdf

[2] NERC Standards Independent Expert Review Project, An Independent Review by Industry Experts, posted at http://www.nerc.com/pa/Stand/Standards%20Development%20Plan%20Library/Standards_Independent_Experts_Review_Project_Report.pdf

- EOP-003-2, R5 - P81. Duplicative of R1 and also covered under standards for TOP (TOP-002-3)
- EOP-003-2, R6 - P81. Duplicative; an entity does the same actions as when not islanded.
- EOP-003-2, R7 - P81. Duplicative of PRC-010 R1

As part of the EOP Five-Year Review process, the EOP FYRT evaluated these recommendations and generally agrees with them, with exceptions and further considerations for the standard drafting team, as noted below:

- EOP-001-2.1b - the EOP FYRT concurred with the recommendation to retire R6 in accordance with the applicable Paragraph 81 criteria (Requirements 6.1 and 6.3 under Criterion B7; Requirement R6.2 under Criterion B6; and Requirement R6.4 under Criterion A). In addition, the EOP FYRT also recommended that the future EOP SDT take into consideration retiring Requirements R3.1 under Criterion B7, Requirement R3.2 under Criterion B7 and Criterion A, and Requirement R3.4 under Criterion B1 of Paragraph 81. The EOP FYRT further recommended revising and merging EOP-001-2.b and EOP-002-3.1 into a single standard; revising Requirements R1, R2 and R5 and reviewing Attachment 1.
- EOP-002-3.1 - in addition to Requirements R6 and R9, the EOP FYRT recommended retiring Requirements R1 under Criterion B7 of Paragraph 81. The EOP FYRT further recommended that the future EOP SDT consider revising and merging EOP-001-2.b and EOP-002-3.1 into a single standard, which would include a revision to Requirement R3 and Attachment 1.
- EOP-003-2 - the EOP FYRT recommended Requirements R2, R4 and R7 be moved to PRC-010-0 and revised in accordance with the other requirements in that standard. In addition to merging EOP-001-2.1b with EOP-002-3.1, the EOP FYRT recommended the future EOP SDT consider merging EOP-003-2, EOP-001-1-2.1b and EOP-002-3.1 into a single standard.

The EOP FYRT made a strong recommendation for the EOP SDT to consider merging and revising EOP-001-2.b and EOP-002-3.1 into a single standard; not only to streamline and clarify the requirements after applying the Paragraph 81 criteria, but also to invoke the continuous improvement cycle of the reliability standards towards results-based standards (RBS).

Paragraph 81[3]

For a reliability standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy both: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B (identifying criteria). In addition, for each reliability standard requirement proposed for retirement or modification, the data and reference points of Criterion C should be considered for making a more informed decision.

[3] NERC – Paragraph 81 Criteria posted at http://www.nerc.com/pa/stand/project%20200812%20coordinate%20interchange%20standards%20dl/paragraph_81_criteria.pdf

Paragraph 81 recommendations from the Independent Experts and Industry were reviewed and the EOP SDT incorporated those into the development of EOP-011-1.

FERC Directives

In the development of the proposed EOP-011-1 reliability standard, the EOP SDT addressed the outstanding FERC directives in Order No. 693 related to Emergency Operations and planning[4]. The directives applicable to each standard are listed below:

EOP-001-1 Emergency Operations Planning:

- Include reliability coordinators as an applicable entity.
- Consider Southern California Edison's and Xcel's suggestions in the standard development process.
- Clarify that the 30-minute requirement in requirement R2 to state that Load shedding should be capable of being implemented as soon as possible but no more than 30 minutes.
- Includes definitions of system states (e.g. normal, alert, emergency), criteria for entering into these states. And the authority that will declare them.
  - Consider a pilot program (field test) for the system states proposal.
  - Clarifies that the actual emergency plan elements, and not the "for consideration" elements of Attachment 1, should be the basis for compliance.

EOP-002-2 Capacity and Energy Emergencies:

- Address emergencies resulting not only from insufficient generation but also insufficient
- Transmission capability, particularly as it affects the implement of the capacity and energy Emergency plan. Include all technically feasible resource options, including demand response and generation resources.
- Ensure the TLR procedure is not used to mitigate actual IROL violations.

EOP-003-1 Load Shedding Plans:

- Develop specific minimum Load shedding capability that should be provided and the maximum amount of delay before Load shedding can be implemented based on overarching nationwide criteria that take into account system characteristics.
- Require periodic drills of simulated Load shedding.
- Suggest a review of industry best practices in determining nationwide criteria.
- Consider comments from APPA and ISO-NE in the standards development process.

Rationales for Requirements

[4] Outstanding FERC Order 693 directives listing related to Emergency Operations posted at [Project 2009-03 Directives.xlsx]

Proposed reliability standard EOP-011-1 merges EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 into a single standard applicable to the following functional entities:

- Balancing Authority
- Reliability Coordinator
- Transmission Operator

Requirement R1:
The EOP SDT examined the recommendation of the EOP FYRT and FERC directive to provide guidance on applicable entity responsibility that was included in EOP-001-2.1b. The EOP SDT removed EOP-001-2.1b, Attachment 1 and incorporated it into this standard under the applicable requirements. The EOP SDT identified that in Attachment 1 there are elements that would not relate to the Transmission Operator and removed them from this requirement. These elements were listed in the original standard and have been retained in this standard. This also establishes a requirement for the Transmission Operator to create its Operating Plan(s) to mitigate operating Emergencies to address capacity and energy Emergencies.

Requirement R2:
As with Requirement R1, the EOP SDT took the recommendation of the FYRT and the FERC directive to provide guidance on applicable entity responsibility in EOP-001-2.1b, Attachment 1 as it relates to the Balancing Authority. The EOP SDT identified that in Attachment 1 there are elements that would not relate to the Balancing Authority and removed them from this requirement. These elements were listed in the original standard and have been retained in this standard. This also establishes a requirement for the Balancing Authority to create its Operating Plan(s) to mitigate Capacity Emergencies and Energy Emergencies within its Balancing Authority Area.

Requirement R3:
The EOP SDT agrees that Transmission Operators and Balancing Authorities should submit Operating Plan(s) to mitigate operating Emergencies to the Reliability Coordinator for review in order for its Reliability Coordinator to ensure reliability risks are identified between Operating Plans to mitigate operating Emergencies in its Reliability Coordinator Area. The EOP SDT also has created this requirement so that it is similar in structure to the EOP-006-2, Requirement 5.1. The Requirement reflects the directive of the Federal Energy Regulator Commission to have the Reliability Coordinator involved in the Operating Plans of the Transmission Operator and Balancing Authority.

"…the Commission finds the reliability coordinator is a necessary entity under EOP-001-0 and directs the ERO to modify the Reliability Standard to include the reliability coordinator as an applicable entity."

Requirement R4:
The EOP SDT added Requirement R4 to support the coordination of Operating Plans within a Reliability Coordinator Area in order to identify and correct and Wide Area reliability risks.

Requirement R5:

The EOP SDT added the words “within a time period specified by its Reliaibility Coordinator” to the requirement to point to the timeliness and to the relevancy of the Emergencies and to alleviate excessive notifications by Balancing Authorities and Transmission Operators. This was an existing requirement in EOP-002-3.1 for Balancing Authorities.

Requirement R6:

The EOP SDT retained Requirement R8 from E0P-002-3.1. The Load-Serving Entity does not have any requirements to request an Energy Emergency Alert (EEA) be issued. The Load-Serving Entity could request an EEA be be issued through its Balancing Authority. The Load-Serving Entity has no Real-time reliability functionality with respect to EEAs. ; therefore, the EOP SDT elected to remove the Load-Serving Entity in the requirement and Attachment 1. The EOP SDT also ensured Requirement R6 was created to address the FERC directive to have the Reliability Coordinator involved to ensure that the Energy Emergency alert gets initiated.

Conclusion:

The proposed EOP-011-1 reliability standard builds upon the current EOP-001-2.1b, EOP-002-3.1 and EOP-003-2 and with the consolidation of the standards, this will streamline the requirements for Emergency Operations for the BES into a clearer and more concise standard. This new standard aligns these requirements to the appropriate entities needed during Capacity Emergency and Energy Emergency situations on the BES. It establishes a structured roadmap of entity-to-entity communication and a process to ensure proper coordination of capacity situations during emergency events. As such, the proposed EOP-011-1 reliability standard satisfies the Reliability Principles identified at the beginning and is appropriate for approval of the NERC Board of Trustees and other applicable regulatory authorities.

Standards Authorization Request Form

When completed, please email this form to:
sarcomm@nerc.com

NERC welcomes suggestions to improve the reliability of the bulk power system through improved reliability standards. Please use this form to submit your request to propose a new or a revision to a NERC's Reliability Standard.

Request to propose a new or a revision to a Reliability Standard			
Title of Proposed Standard:	Emergency Operations (EOP-001-3, EOP-002-4, EOP-003-3)		
Date Submitted:	October 17, 2013		
SAR Requester Information			
Name:	David McRee, Chair EOP Five-Year Review Team (FYRT)		
Organization:	Duke Energy		
Telephone:	(704) 382-9841	E-mail:	David.McRee@duke-energy.com
SAR Type (Check as many as applicable)			
☐ New Standard		☒ Withdrawal of existing Standard	
☒ Revision to existing Standard		☐ Urgent Action	

SAR Information
Industry Need (What is the industry problem this request is trying to solve?):
This SAR will address the Five-Year Review requirement for these standards.
Purpose or Goal (How does this request propose to address the problem described above?):
To improve the quality, relevance, and clarity of the standards. Also bring the standards into the Results Based Standards format.

SAR Information
Identify the Objectives of the proposed standard's requirements (What specific reliability deliverables are required to achieve the goal?):
To increase the effectiveness of the three standards in their ability to ensure reliability of the BES.
Brief Description (Provide a paragraph that describes the scope of this standard action.)
The EOP SDT will consider the comments received from the EOP Five Year Review Team (FYRT), which includes consideration of industry comments and the report from the Industry Expert Review Panel. Recommendations for consideration are: • Modify the requirements and attachments to improve their clarity and measurability, while removing ambiguity • Move and/or streamline requirements • Eliminate requirements based on P81 criteria • Coordinate with Project 2008-02 UVLS to eliminate duplicative requirements • Apply Paragraph 81 criteria and recommendations from Independent Expert Review Panel on standards EOP-001, -002, and -003. To ensure a seamless transition from the EOP FYRT to the future EOP SDT, the EOP FYRT recommends the inclusion of interested EOP FYRT members to participate on the EOP SDT. In addition, the EOP FYRT should provide a high-level overview of their recommendations as a formal kick-off to the future EOP SDT meetings.
Detailed Description (Provide a description of the proposed project with sufficient details for the standard drafting team to execute the SAR. Also provide a justification for the development or revision of the standard, including an assessment of the reliability and market interface impacts of implementing or not implementing the standard action.)
See the attached Five-Year Review templates of the three standards, consideration of comments, issues and directives list, redlined standards (reflecting deletions), and the Industry Experts' anyalsis.

Reliability Functions	
The Standard will Apply to the Following Functions (Check each one that applies.)	
☒ Reliability Coordinator	Responsible for the real-time operating reliability of its Reliability Coordinator Area in coordination with its neighboring Reliability Coordinator's wide area view.

Reliability Functions		
☒	Balancing Authority	Integrates resource plans ahead of time, and maintains load-interchange-resource balance within a Balancing Authority Area and supports Interconnection frequency in real time.
☐	Interchange Authority	Ensures communication of interchange transactions for reliability evaluation purposes and coordinates implementation of valid and balanced interchange schedules between Balancing Authority Areas.
☐	Planning Coordinator	Assesses the longer-term reliability of its Planning Coordinator Area.
☐	Resource Planner	Develops a >one year plan for the resource adequacy of its specific loads within a Planning Coordinator area.
☐	Transmission Planner	Develops a >one year plan for the reliability of the interconnected Bulk Electric System within its portion of the Planning Coordinator area.
☐	Transmission Service Provider	Administers the transmission tariff and provides transmission services under applicable transmission service agreements (e.g., the pro forma tariff).
☐	Transmission Owner	Owns and maintains transmission facilities.
☒	Transmission Operator	Ensures the real-time operating reliability of the transmission assets within a Transmission Operator Area.
☐	Distribution Provider	Delivers electrical energy to the End-use customer.
☐	Generator Owner	Owns and maintains generation facilities.
☒	Generator Operator	Operates generation unit(s) to provide real and reactive power.
☐	Purchasing-Selling Entity	Purchases or sells energy, capacity, and necessary reliability-related services as required.
☐	Market Operator	Interface point for reliability functions with commercial functions.
☒	Load-Serving Entity	Secures energy and transmission service (and reliability-related services) to serve the End-use Customer.

Reliability and Market Interface Principles

Reliability and Market Interface Principles	
Applicable Reliability Principles (Check all that apply).	
☒	1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.
☒	2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.
☐	3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.
☒	4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained and implemented.
☐	5. Facilities for communication, monitoring and control shall be provided, used and maintained for the reliability of interconnected bulk power systems.
☐	6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.
☐	7. The security of the interconnected bulk power systems shall be assessed, monitored and maintained on a wide area basis.
☐	8. Bulk power systems shall be protected from malicious physical or cyber attacks.

Does the proposed Standard comply with all of the following Market Interface Principles?	Enter (yes/no)
1. A reliability standard shall not give any market participant an unfair competitive advantage.	Yes
2. A reliability standard shall neither mandate nor prohibit any specific market structure.	Yes
3. A reliability standard shall not preclude market solutions to achieving compliance with that standard.	Yes
4. A reliability standard shall not require the public disclosure of commercially sensitive information. All market participants shall have equal opportunity to access commercially non-sensitive information that is required for compliance with reliability standards.	Yes

Related Standards

Related Standards	
Standard No.	Explanation
BAL-001-0.1a	Real Power Balancing Control Performance
BAL-002-01	Disturbance control standard
BAL-002-WECC	Regional Contingency Reserve standard
COM-001-1.1	Telecommunications
COM-002-2	Communications and Coordination
PRC-010-0	Planning for Undervoltage Load shedding
PER-005-1	Training

Related SARs	
SAR ID	Explanation
	None

Regional Variances	
Region	Explanation
ERCOT	

Regional Variances	
FRCC	
MRO	
NPCC	
RFC	
SERC	
SPP	
WECC	

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Five-Year Review Template – EOP-001-2.1b

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-001-2.1b Emergency Operations Planning
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111, ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:
   Requirement R3:

   - Requirement R3.1 should be covered by EOP-001-2.1b Requirement R4 in Attachment 1 (notifications that should be included in the plan are identified). COM-001 and COM-002 are descriptive in the identification of protocols to use and, thus, adequately cover the generic reference. With the recommended revision to Attachment 1 of EOP-001-2.1b, along with COM-001 and COM-002 generic reference, Requirement R3.1 would meet Criterion B7 as redundant, as well as Criterion A (Requirement R3.1 does little, if anything, to benefit or protect the reliable operation of the BES) of Paragraph 81 and should be retired.
   - Requirement R3.2 should be covered by EOP-001-2.1b Requirement R4 in Attachment 1, which lists the actions to take during capacity situations specified in the plan. Load reduction within timelines is covered in BAL-002 Requirement R2. With the recommended revision of EOP-001 Requirement R4, Requirement R3.2 would meet Criterion B7 as redundant, as well as Criterion A (R3.1 does little, if anything, to benefit or protect the reliable operation of the BES) of Paragraph 81 and should be retired.
   - Requirement R3.4 meets Paragraph 81 Criterion B1; staffing levels are administrative in nature and would result in an increase in efficiency in the ERO compliance program (it is a simple check off during an audit). Requirement R3.4 also meets with Criterion A of Paragraph 81, as a check-off does not enhance the reliability of the BES. Requirement R3.4 should be retired as falling under Criterion B1 and Criterion A of Paragraph 81.

   Requirement 6 in its entirety:

   - Requirement R6.1 is redundant with COM-001, meeting Criterion B7 as redundant under Paragraph 81 and should be retired.
   - Requirement R6.2 speaks to an action to be taken during capacity issues that is not feasible in accomplishing. Transaction arrangements are also a commercial practice and, thus, Requirement R6.2 meets Criterion B6 of Paragraph 81 and should be retired.

- Requirement R6.3 is redundant with EOP-001-2b Requirement R4 and Attachment 1, whereby meeting Criterion B7 as redundant under Paragraph 81 and should be retired.
- Requirement R6.4 does not provide for benefit for reliability of the BES, meeting Criterion A of Paragraph 81 and should be retired.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

    a. Is this a Version 0 Reliability Standard?
    b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
    c. Are the requirements consistent with the purpose of the Reliability Standard?

    ☒ Yes

    ☐ No

    Please summarize your assessment:
    The 2009-03 Emergency Operations Five-Year Review Team (EOP FYRT) recommends that EOP-001-2.b and EOP-002-3.1 be revised and merged into a single standard identifying clearly and separately the Transmission Operator, Generation Operator and Reliability Coordinator issues as they relate to the BA and TOP (to address Paragraph 548 of Order 693) and how it needs to be planned and implemented for on the BES by the specific functional entities.

    - Requirement R1 needs clarity provided as to what an operating agreement constitutes, and adjust the VSL to reflect current interpretations with the number of agreements needed. Requirement R1 must also account for current interpretations found in the Appendix and other interpretations.
    - Requirement R2 needs clarity provided, as instructed by the Commission, on the ambiguity of the EOP standards as they relate to the responsibilities of the Transmission Operator and Balancing Authority.
    - Requirement R5, the need to share emergency plans with neighboring Transmission Operators and Balancing Authorities, should be removed as an administrative burden (identified in P81); however, the remaining language of the requirement should be affirmed.
    - Review is recommended for Attachment 1 as it relates to the GOP in light of recent BES events (Cold Weather Event).

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☒ Yes

☐ No

Please explain:
Appendix 1 attempts to define what a remote Balancing Authority is and should be addressed in future revisions of the Standard

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

   Additional measures must be provided with this standard. There are no performance measures. There are no VRFs with this standard. Requirement R1, once recommended clarity is provided as to what an operating agreement constitutes, adjustment to the VSL will be necessary to reflect current interpretations with the number of agreements needed.

   ☐ Yes

   ☒ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

   ☐ Yes

   ☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☐ Yes

☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

☒ Yes
☐ No

Guiding Questions:

If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE – Requirement R1, R2, R5 and Attachment 1

☒ RETIRE – Requirements R3.1, R3.2, R3.4, R6.1, R6.2, R6.3, R6.4

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE – Requirements R1, R2, R5 and Attachment 1

☒ RETIRE – Requirements R3.1, R3.2, R3.4; Requirement R6 in its entirety; R6.1, R6.2, R6.3, R6.4

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

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[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant

The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board (“NAESB”), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)

Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?

The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?

The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection (“CIP”) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?

The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

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Five-Year Review Template – EOP-002-3

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-002-3.1 Capacity and Energy Emergencies
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111,ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information ***(to be completed by NERC staff)***

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   - Requirement R1 is redundant with IRO-001 and PER-001-2 and should be retired under Criterion B7 of Paragraph 81.
   - Requirement R6 is redundant with BAL-002-1a and should be retired under Criterion B7 of Paragraph 81.
   - Requirement R9 was in place to allow for a Transmission Service Provider to change the priority of a service request, informing the Reliability Coordinator so that the service would not be curtailed by a TLR, and since the Tagging Specs did not allow profiles to be changed, this was the only method to accomplish it. Under NAESB WEQ Etag Spec v1811 R3.6.1.3, this has been modified and now the TSP has the ability to change the Transmission priority which, in turn, is reflected in the IDC. This technology change allows for the deletion of Requirement R9 in its entirety. Requirement R9 meets with Criterion A of Paragraph 81 and should be retired. Due to the retirement of R9, LSE applicability should be removed in the standard.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

Please summarize your assessment:
The EOP FYRT recommends that EOP-001-2b and EOP-002-3.1 be revised and merged into a single standard to address redundancy in the stating that a plan should be implemented. Both standards are different enough that those requirements not identified in retirement recommendations under Paragraph 81 should be retained.

Requirement R8 and Attachment 1 have several issues regarding applicability to different functions and should be revised to eliminate discrepancies and for clarity. Attachment 1 needs to be reviewed for consistency with IRO and TOP standards. The EOP FYRT recommends review of the uniqueness as it relates to ERCOT and similarly situated BAs. The EOP FYRT recommends the future EOP SDT address the directive in Paragraph 573 of Order 693.

The EOP FYRT further recommends a language change in Requirement R2, replacing "interconnected system" with "Bulk Electric System." Requirements R3 and R4 need to be reviewed by the future EOP SDT to further define the word "emergency" (as Capacity Emergency, Emergency, and Energy Emergency are already NERC defined terms). The EOP FYRT recommends the following sentence in Requirement R5 to be struck: "Such unilateral adjustment may overload transmission facilities."

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes

☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

☒ Yes

☐ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or

consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

☐ Yes

☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised: Requirement R9 (recommended for retirement under Paragraph 81) the TSP now has the ability to change the Transmission priority, which is in turn reflected in the IDC.

   ☒ Yes

   ☐ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE (and merge with EOP-001-2b)

☒ RETIRE – Requirements R1, R6 and R9 in its entirety.

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE (and merge with EOP-001-2b); Requirement R2, replacing “interconnected system” with “Bulk Electric System;” language revision in Requirement R2; Requirements R3 and R4 need to be reviewed by the future EOP SDT to further define the word “emergency” (as Capacity Emergency, Emergency, and Energy Emergency are already NERC defined terms); Requirement R5, strike “Such unilateral adjustment may overload transmission facilities.”

☒ RETIRE – Requirements R1, R6, and R9 in its entirety. Due to the retirement of R9, LSE applicability should be removed in the standard.

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board ("NAESB"), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection ("CIP") requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Five-Year Review Template – EOP-003-2

Submitted to Standards Committee October 17, 2013

Introduction

NERC has an obligation to conduct a five-year review of each Reliability Standard developed through NERC's American National Standards Institute-accredited Reliability Standards development process.[1] The Reliability Standard identified below is due for a five-year review. Your review team should use the background information and the questions below, along with any associated worksheets or reference documents, to guide a comprehensive review that results in a recommendation that the Reliability Standard should be (1) affirmed as is (i.e., no changes needed); (2) revised (which may include revising or retiring one or more requirements); or (3) withdrawn. If the team recommends a revision to the Reliability Standard, it should also submit a draft Standard Authorization Request (SAR) outlining the proposed scope and technical justification for the revision.

A completed five-year review template and any associated documentation should be submitted by email to Laura Hussey, Director of Standards Development at laura.hussey@nerc.net.

Applicable Reliability Standard: EOP-003-2 Load Shedding Plans
Team Members (include name, organization, phone number, and email address): 1. Chair - David McRee, Duke Energy, 704-382-9841, david.mcree@duke-energy.com 2. Vice Chair – Francis Halpin, Bonneville Power, 503-230-7545, fjhalpin@bpa.gov 3. Richard Cobb, Midcontinent ISO, Inc., 651-632-8468, rcobb@misoenergy.org 4. Jen Fiegel, Oncor Electric, 214-743-6825, jfiegel1@oncor.com 5. Hal Haugom, Madison Gas & Electric, 608-252-5608, hhaugom@mge.com 6. Steve Lesiuta, Ontario Power Generation, 416-231-4111, ext. 4034, steve.lesiuta@opg.com 7. Connie Lowe, Dominion Resources Services, Inc., 804-819-2917, connie.lowe@dom.com 8. Brad Young, LG&E/KU, 859-367-5703, brad.young@lge-ku.com
Date Review Completed: September 24, 2013

[1] NERC *Standard Processes Manual*, posted at http://www.nerc.com/files/Appendix_3A_Standard_Processes_Manual_20110825.pdf, at page 41.

Background Information *(to be completed by NERC staff)*

1. Are there any outstanding Federal Energy Regulatory Commission directives associated with the Reliability Standard? (If so, NERC staff will attach a list of the directives with citations to associated FERC orders for inclusion in a SAR.)

   ☒ Yes

   ☐ No

2. Have stakeholders requested clarity on the Reliability Standard in the form of an Interpretation (outstanding, in progress, or approved), Compliance Application Notice (CAN) (outstanding, in progress, or approved), or an outstanding submission to NERC's Issues Database? (If there are, NERC staff will include a list of the Interpretation(s), CAN(s), or stakeholder-identified issue(s) contained in the NERC Issues Database that apply to the Reliability Standard.)

   ☒ Yes

   ☐ No

3. Is the Reliability Standard one of the most violated Reliability Standards? If so, does the root cause of the frequent violation appear to be a lack of clarity in the language?

   ☐ Yes

   ☒ No

   Please explain:

4. Does the Reliability Standard need to be converted to the results-based standard format as outlined in *Attachment 1: Results-Based Standards*? (Note that the intent of this question is to ensure that, as Reliability Standards are reviewed, the formatting is changed to be consistent with the current format of a Reliability Standard. If the answer is yes, the formatting should be updated when the Reliability Standard is revised.)

   ☒ Yes

   ☐ No

Questions for SME Review Team

If NERC staff answered "Yes" to any of the questions above, the Reliability Standard probably requires revision. The questions below are intended to further guide your review. Some of the questions reference documents provided by NERC staff as indicated in the Background questions above.

1. **Paragraph 81**: Does one or more of the requirements in the Reliability Standard meet criteria for retirement or modification based on Paragraph 81 concepts? Use *Attachment 2: Paragraph 81 Criteria* to make this determination.

   ☒ Yes

   ☐ No

   Please summarize your application of Paragraph 81 Criteria, if any:

   - Requirements R5 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R5 speaks to shedding loads in steps; that same process will be done in Requirement R1. Requirement R5 should be retired under Criterion B7 of Paragraph 81.
   - Requirements R6 is a refinement to EOP-003-2 Requirement R1 and is duplicative in nature to that requirement. Requirement R6 speaks of two events that must be valid to tell the BA or TOP to shed more load, but overall the action of shedding load to meet insufficient generation is the same as stated in Requirement R1. Requirement R6 should be retired under Criterion B7 of Paragraph 81.
   - EOP-003-2– Recommend that Requirements R2, R4 and R7 be moved to PRC-010-0 or otherwise addressed during Project 2008-02 – Undervoltage Load Shedding.

2. **Clarity:** If the Reliability Standard has an Interpretation, CAN, or issue associated with it, or is frequently violated because of ambiguity, it probably needs to be revised for clarity. Beyond these indicators, is there any reason to believe that the Reliability Standard should be modified to address a lack of clarity? Consider:

   a. Is this a Version 0 Reliability Standard?
   b. Does the Reliability Standard have obviously ambiguous language or language that requires performance that is not measurable?
   c. Are the requirements consistent with the purpose of the Reliability Standard?

   ☒ Yes

   ☐ No

Please summarize your assessment:
The EOP FYRT team believes that Requirements R2, R4 and R7 should be coordinated with the revision of PRC-010 (Project 2008-02 Undervoltage Load Shedding) for inclusion in that standard. This is consistent with the review that was done for automatic underfrequency requirements and should also be performed for automatic undervoltage requirements.

Based on the recommendations received during the comment period, EOP FYRT further recommends R1 and R8 be considered to be combined. The EOP FYRT also received comments that EOP-003-2 should be combined with EOP-001-2.1b and EOP-002-3.1, and the EOP FYRT recommends this be evaluated in the SAR. In addition, the EOP FYRT recommends that the future EOP SDT evaluate the separation of the functional entity capabilities of the BA and the TOP responsibilities.

3. **Definitions**: Do any of the defined terms used within the Reliability Standard need to be refined?

☐ Yes

☒ No

Please explain:

4. **Compliance Elements:** Are the compliance elements associated with the requirements (Measures, Data Retention, VRFs, and VSLs) consistent with the direction of the Reliability Assurance Initiative and FERC and NERC guidelines? If you answered "No," please identify which elements require revision, and why:

The Measures and Data retention should be reviewed and updated

☐ Yes

☒ No

5. **Consistency with Other Reliability Standards:** Does the Reliability Standard need to be revised for formatting and language consistency among requirements within the Reliability Standard or consistency with other Reliability Standards? If you answered "Yes," please describe the changes needed to achieve formatting and language consistency:

☐ Yes

☒ No

6. **Changes in Technology, System Conditions, or other Factors:** Does the Reliability Standard need to be revised to account for changes in technology, system conditions, or other factors? If you answered "Yes," please describe the changes and specifically what the potential impact is to reliability if the Reliability Standard is not revised:

   ☐ Yes

   ☒ No

7. **Consideration of Generator Interconnection Facilities:** Is responsibility for generator interconnection Facilities appropriately accounted for in the Reliability Standard?

   ☒ Yes
   ☐ No

   Guiding Questions:

   If the Reliability Standard is applicable to GOs/GOPs, is there any ambiguity about the inclusion of generator interconnection Facilities? (If generation interconnection Facilities could be perceived to be excluded, specific language referencing the Facilities should be introduced in the Reliability Standard.)

   If the Reliability Standard is not applicable to GOs/GOPs, is there a reliability-related need for treating generator interconnection Facilities as transmission lines for the purposes of this Reliability Standard? (If so, GOs and GOPs that own or operate relevant generator interconnection Facilities should be explicit in the applicability section of the Reliability Standard.)

Recommendation

The answers to the questions above, along with a preliminary recommendation of the SMEs conducting the review of the Reliability Standard, will be posted for a 45-day informal comment period, and the comments publicly posted. The SMEs will review the comments to evaluate whether to modify their initial recommendation, and will document the final recommendation which will be presented to the Standards Committee.

Preliminary Recommendation (to be completed by the SME team after its review and prior to posting the results of the review for industry comment):

☐ AFFIRM

☒ REVISE – Retire Requirements R5, R6, R2, R4 and R7 and address directives in Paragraphs 595 and 603 of Order 693

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*: See responses to questions 1, 2, and 4 above.

Preliminary Recommendation posted for industry comment (date): 08/06/2013 – 09/19/2013

Final Recommendation (to be completed by the SME team after it has reviewed industry comments on the preliminary recommendation):

☐ AFFIRM *(This should only be checked if there are no outstanding directives, interpretations or issues identified by stakeholders.)*

☒ REVISE - Retire Requirements R5, R6, R2, R4 and R7 and address directives in Paragraphs 595 and 603 or Order 693; recommend for consideration Requirements R1 and R8 be combined; consider combining EOP-003-2 with EOP-001-2.1b and EOP-002-3.1; evaluate the separation of the functional entity capabilities of the BA and TOP responsibilities.

☐ RETIRE

Technical Justification *(If the SME team recommends that the Reliability Standard be revised, a draft SAR may be included and the technical justification included in the SAR)*:

Date submitted to NERC Staff:

Attachment 1: Results-Based Standards

The fourth question for NERC staff asks if the Reliability Standard needs to be converted to the results-based standards (RBS) format. The information below will be used by NERC staff in making this determination, and is included here as a reference for the SME team and other stakeholders.

RBS standards employ a defense-in-depth strategy for Reliability Standards development where each requirement has a role in preventing system failures and the roles are complementary and reinforcing. Reliability Standards should be viewed as a portfolio of requirements designed to achieve an overall defense-in-depth strategy and comply with the quality objectives identified in the resource document titled, "Acceptance Criteria of a Reliability Standard."

A Reliability Standard that adheres to the RBS format should strive to achieve a portfolio of performance-, risk-, and competency-based mandatory reliability requirements that support an effective defense-in-depth strategy. Each requirement should identify a clear and measurable expected outcome, such as: a) a stated level of reliability performance, b) a reduction in a specified reliability risk, or c) a necessary competency.

a. **Performance-Based**—defines a particular reliability objective or outcome to be achieved. In its simplest form, a results-based requirement has four components: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome?

b. **Risk-Based**—preventive requirements to reduce the risks of failure to acceptable tolerance levels. A risk-based reliability requirement should be framed as: who, under what conditions (if any), shall perform what action, to achieve what particular result or outcome that reduces a stated risk to the reliability of the bulk power system?

c. **Competency-Based**—defines a minimum set of capabilities an entity needs to have to demonstrate it is able to perform its designated reliability functions. A competency-based reliability requirement should be framed as: who, under what conditions (if any), shall have what capability, to achieve what particular result or outcome to perform an action to achieve a result or outcome or to reduce a risk to the reliability of the bulk power system?

Additionally, each RBS-adherent Reliability Standard should enable or support one or more of the eight reliability principles listed below. Each Reliability Standard should also be consistent with all of the reliability principles.

1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

8. Bulk power systems shall be protected from malicious physical or cyber attacks.

If the Reliability Standard does not provide for a portfolio of performance-, risk-, and competency-based requirements or consistency with NERC's reliability principles, NERC staff should recommend that the Reliability Standard be reformatted in accordance with RBS format.

Attachment 2: Paragraph 81 Criteria

The first question for the SME Review Team asks if one or more of the requirements in the Reliability Standard meet(s) criteria for retirement or modification based on Paragraph 81 concepts.[2] Use the Paragraph 81 criteria explained below to make this determination. Document the justification for the decisions throughout and provide them in the final assessment in the Five-Year Review worksheet.

For a Reliability Standard requirement to be proposed for retirement or modification based on Paragraph 81 concepts, it must satisfy **both**: (i) Criterion A (the overarching criterion) and (ii) at least one of the Criteria B listed below (identifying criteria). In addition, for each Reliability Standard requirement proposed for retirement or modification, the data and reference points set forth below in Criteria C should be considered for making a more informed decision.

Criterion A (Overarching Criterion)

The Reliability Standard requirement requires responsible entities ("entities") to conduct an activity or task that does little, if anything, to benefit or protect the reliable operation of the BES.

Section 215(a) (4) of the United States Federal Power Act defines "reliable operation" as: "… operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements."

Criteria B (Identifying Criteria)

B1. Administrative

The Reliability Standard requirement requires responsible entities to perform a function that is administrative in nature, does not support reliability and is needlessly burdensome.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability and whose retirement or modification will result in an increase in the efficiency of the ERO compliance program. Administrative functions may include a task that is related to developing procedures or plans, such as establishing communication contacts. Thus, for certain requirements, Criterion B1 is closely related to Criteria B2, B3 and B4. Strictly administrative functions do not inherently negatively impact reliability directly and, where possible, should be eliminated or modified for purposes of efficiency and to allow the ERO and entities to appropriately allocate resources.

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[2] In most cases, satisfaction of the Paragraph 81 criteria will result in the retirement of a requirement. In some cases, however, there may be a way to modify a requirement so that it no longer satisfies Paragraph 81 criteria. Recognizing that, this document refers to both options.

B2. Data Collection/Data Retention
These are requirements that obligate responsible entities to produce and retain data which document prior events or activities, and should be collected via some other method under NERC's rules and processes.

This criterion is designed to identify requirements that can be retired or modified with little effect on reliability. The collection and/or retention of data do not necessarily have a reliability benefit and yet are often required to demonstrate compliance. Where data collection and/or data retention is unnecessary for reliability purposes, such requirements should be retired or modified in order to increase the efficiency of the ERO compliance program.

B3. Documentation
The Reliability Standard requirement requires responsible entities to develop a document (*e.g.,* plan, policy or procedure) which is not necessary to protect BES reliability.

This criterion is designed to identify requirements that require the development of a document that is unrelated to reliability or has no performance or results-based function. In other words, the document is required, but no execution of a reliability activity or task is associated with or required by the document.

B4. Reporting
The Reliability Standard requirement obligates responsible entities to report to a Regional Entity, NERC or another party or entity. These are requirements that obligate responsible entities to report to a Regional Entity on activities which have no discernible impact on promoting the reliable operation of the BES and if the entity failed to meet this requirement there would be little reliability impact.

B5. Periodic Updates
The Reliability Standard requirement requires responsible entities to periodically update (*e.g.,* annually) documentation, such as a plan, procedure or policy without an operational benefit to reliability.

This criterion is designed to identify requirements that impose an updating requirement that is out of sync with the actual operations of the BES, unnecessary, or duplicative.

B6. Commercial or Business Practice
The Reliability Standard requirement is a commercial or business practice, or implicates commercial rather than reliability issues.

This criterion is designed to identify those requirements that require: (i) implementing a best or outdated business practice or (ii) implicating the exchange of or debate on commercially sensitive information while doing little, if anything, to promote the reliable operation of the BES.

B7. Redundant
The Reliability Standard requirement is redundant with: (i) another FERC-approved Reliability Standard requirement(s); (ii) the ERO compliance and monitoring program; or (iii) a governmental regulation (*e.g.,* Open Access Transmission Tariff, North American Energy Standards Board (“NAESB”), etc.).

This criterion is designed to identify requirements that are redundant with other requirements and are, therefore, unnecessary. Unlike the other criteria listed in Criterion B, in the case of redundancy, the task or activity itself may contribute to a reliable BES, but it is not necessary to have two duplicative requirements on the same or similar task or activity. Such requirements can be retired or modified with little or no effect on reliability and removal will result in an increase in efficiency of the ERO compliance program.

Criteria C (Additional data and reference points)
Use the following data and reference points to assist in the determination of (and justification for) whether to proceed with retirement or modification of a Reliability Standard requirement that satisfies both Criteria A and B:

C1. Was the Reliability Standard requirement part of a FFT filing?
The application of this criterion involves determining whether the requirement was included in a FFT filing.

C2. Is the Reliability Standard requirement being reviewed in an ongoing Standards Development Project?
The application of this criterion involves determining whether the requirement proposed for retirement or modification is part of an active Standards Development Project, with consideration for the status of the project. If the requirement has been approved by Registered Ballot Body and is scheduled to be presented to the NERC Board of Trustees, in most cases it will not need to be addressed in the five-year review. The exception would be a requirement, such as the Critical Information Protection (“CIP”) requirements for Version 3 and 4, that is not due to be retired for an extended period of time. Also, for informational purposes, whether the requirement is included in a future or pending Standards Development Project should be identified and discussed.

C3. What is the VRF of the Reliability Standard requirement?
The application of this criterion involves identifying the VRF of the requirement proposed for retirement or modification, with particular consideration of any requirement that has been assigned as having a Medium or High VRF. Also, the fact that a requirement has a Lower VRF is not dispositive that

it qualifies for retirement or modification. In this regard, Criterion C3 is considered in light of Criterion C5 (Reliability Principles) and C6 (Defense in Depth) to ensure that no reliability gap would be created by the retirement or modification of the Lower VRF requirement. For example, no requirement, including a Lower VRF requirement, should be retired or modified if doing so would harm the effectiveness of a larger scheme of requirements that are purposely designed to protect the reliable operation of the BES.

C4. In which tier of the most recent Actively Monitored List (AML) does the Reliability Standard requirement fall?
The application of this criterion involves identifying whether the requirement proposed for retirement or modification is on the most recent AML, with particular consideration for any requirement in the first tier of the AML.

C5. Is there a possible negative impact on NERC's published and posted reliability principles?
The application of this criterion involves consideration of the eight following reliability principles published on the NERC webpage.

Reliability Principles
NERC Reliability Standards are based on certain reliability principles that define the foundation of reliability for North American bulk power systems. Each reliability standard shall enable or support one or more of the reliability principles, thereby ensuring that each standard serves a purpose in support of reliability of the North American bulk power systems. Each reliability standard shall also be consistent with all of the reliability principles, thereby ensuring that no standard undermines reliability through an unintended consequence.

Principle 1. Interconnected bulk power systems shall be planned and operated in a coordinated manner to perform reliably under normal and abnormal conditions as defined in the NERC Standards.

Principle 2. The frequency and voltage of interconnected bulk power systems shall be controlled within defined limits through the balancing of real and reactive power supply and demand.

Principle 3. Information necessary for the planning and operation of interconnected bulk power systems shall be made available to those entities responsible for planning and operating the systems reliably.

Principle 4. Plans for emergency operation and system restoration of interconnected bulk power systems shall be developed, coordinated, maintained, and implemented.

Principle 5. Facilities for communication, monitoring, and control shall be provided, used, and maintained for the reliability of interconnected bulk power systems.

Principle 6. Personnel responsible for planning and operating interconnected bulk power systems shall be trained, qualified, and have the responsibility and authority to implement actions.

Principle 7. The reliability of the interconnected bulk power systems shall be assessed, monitored, and maintained on a wide-area basis.

Principle 8. Bulk power systems shall be protected from malicious physical or cyber attacks. (footnote omitted).

C6. Is there any negative impact on the defense in depth protection of the BES?
The application of this criterion considers whether the requirement proposed for retirement or modification is part of a defense in depth protection strategy. In order words, the assessment is to verify whether other requirements rely on the requirement proposed for retirement or modification to protect the BES.

C7. Does the retirement or modification promote results or performance based Reliability Standards?
The application of this criterion considers whether the requirement, if retired or modified, will promote the initiative to implement results- and/or performance-based Reliability Standards.

Proposed Definitions for the NERC Glossary of Terms

Project 2009-03: Emergency Operations

The Emergency Operations Standards Drafting Team (EOP SDT) proposes revisions to a defined term in the NERC Glossary of Terms (Glossary). This defined term is used in the EOP family of standards and in other standards or defined terms as discussed below.

Proposed revised definitions (redlined):

> **Energy Emergency -** A condition when a Load-Serving Entity or Balancing Authority has exhausted all other resource options and can no longer ~~provide~~ meet its ~~customers'~~ expected ~~energy~~ Load ~~requirements~~ obligations.

This defined term is being proposed for revision to provide clarity that an Energy Emergency is not necessarily limited to a Load-Serving Entity.

This defined term, or variations of it, is also used in the instances below. The EOP SDT has determined that the proposed revisions do not change the reliability intent of other requirements or definitions.

- **BAL-002-WECC – Contingency Reserve**: This standard became enforceable on October 1, 2014. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.
- **IRO-005-3.1a — Reliability Coordination — Current Day Operations** - This standard was revised under Project 2006-06 and the reference to Energy Emergency was removed from the standard. The standard was approved by the NERC Board of Trustees (Board) and filed with FERC. NERC has requested that FERC defer action on its petition and is revising this standard under Project 2014-03, TOP / IRO Reliability Standards. This project is scheduled to be completed no later than January 31, 2015. The two standard drafting teams are coordinating the definition revision to ensure there are no redundancies.
- **MOD-004-1 — Capacity Benefit Margin:** This standard is being retired and replaced with MOD-001-2 — Modeling, Data, and Analysis — Available Transmission System Capability (NERC Board approved February 6, 2014). The term "Energy Emergency" is not used in the new standard. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability to the existing approved standard.
- **INT-004-3 – Dynamic Transfers:** This standard was a revision to INT-004-2 under Project 2008-12. INT-004-3 was approved by the NERC Board and filed with FERC. The EOP SDT does not believe that the proposed definition revision will create any redundancies or gaps in reliability.

- **Defined term Emergency Request for Interchange:** This term is not used in any existing approved standard.

Proposed Definitions for the NERC Glossary of Terms

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- **Defined term Emergency Request for Interchange:** This term is not used in any existing approved standard.

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2009-03 Emergency Operations
EOP-011-1

Final Ballot Now Open through November 6, 2014

Now Available

A final ballot for **EOP-011-1 - Emergency Operations** is open through **8 p.m. Eastern, Thursday, November 6, 2014.**

Background information for this project can be found on the project page.

Instructions for Balloting
In the final ballot, votes are counted by exception. Only members of the ballot pool may cast a ballot; all ballot pool members may change their previously cast votes. A ballot pool member who failed to cast a vote during the last ballot window may cast a vote in the final ballot window. If a ballot pool member cast a vote in the previous ballot and does not participate in the final ballot, that member's vote will be carried over in the final ballot.

Members of the ballot pool associated with this project may log in and submit their vote for the standard by clicking here.

Next Steps
The voting results for the standard will be posted and announced after the ballot window closes. If approved, it will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities**.**

For information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Laura Anderson,
Standards Developer, or at 404-446-9671.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower

Atlanta, GA 30326
404-446-2560 | www.nerc.com

NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Standards Announcement

Project 2009-03 Emergency Operations
EOP-011-1

Final Ballot Results

Now Available

A final ballot for **EOP-011-1 – Emergency Operations** concluded at **8 p.m. Eastern, Thursday, November 6, 2014.**

The standard achieved a quorum and received sufficient affirmative votes for approval. Voting statistics are listed below, and the Ballot Results page provides a link to the detailed results for the ballot.

Ballot
Quorum/Approval
87.19% / 73.20%

Background information for this project can be found on the project page.

Next Steps
The standard will be submitted to the Board of Trustees for adoption and then filed with the appropriate regulatory authorities.

For more information on the **Standards Development Process**, please refer to the Standard Processes Manual.

For more information or assistance, please contact Standards Developer, Laura Anderson, or by telephone at 404-446-9671.

North American Electric Reliability Corporation
3353 Peachtree Rd, NE
Suite 600, North Tower
Atlanta, GA 30326
404-446-2560 | www.nerc.com

Ballot Results	
Ballot Name:	Project 2009-03 Emergency Operations EOP-011-1_Final_Ballot_October_2014
Ballot Period:	10/28/2014 - 11/6/2014
Ballot Type:	Final
Total # Votes:	320
Total Ballot Pool:	367
Quorum:	**87.19 % The Quorum has been reached**
Weighted Segment Vote:	73.20 %
Ballot Results:	**A quorum was reached and there were sufficient affirmative votes for approval.**

Summary of Ballot Results

Segment	Ballot Pool	Segment Weight	Affirmative # Votes	Affirmative Fraction	Negative # Votes	Negative Fraction	Negative Vote without a Comment	Abstain	No Vote
1 - Segment 1	100	1	49	0.681	23	0.319	0	10	18
2 - Segment 2	9	0.7	4	0.4	3	0.3	0	2	0
3 - Segment 3	84	1	46	0.667	23	0.333	0	6	9
4 - Segment 4	28	1	19	0.826	4	0.174	0	2	3
5 - Segment 5	78	1	45	0.726	17	0.274	0	6	10
6 - Segment 6	52	1	30	0.698	13	0.302	0	4	5
7 - Segment 7	2	0.1	1	0.1	0	0	0	0	1
8 - Segment 8	5	0.4	4	0.4	0	0	0	0	1
9 -									

Segment 9	2	0.2	2	0.2	0	0	0	0	0
10 - Segment 10	7	0.7	5	0.5	2	0.2	0	0	0
Totals	**367**	**7.1**	**205**	**5.198**	**85**	**1.902**	**0**	**30**	**47**

Individual Ballot Pool Results

Segment	Organization	Member	Ballot	NERC Notes
1	Ameren Services	Eric Scott	Abstain	
1	American Electric Power	Paul B Johnson	Negative	SUPPORTS THIRD PARTY COMMENTS
1	American Transmission Company, LLC	Andrew Z Pusztai	Affirmative	
1	Arizona Public Service Co.	Brian Cole		
1	Associated Electric Cooperative, Inc.	John Bussman	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Austin Energy	James Armke	Affirmative	
1	Avista Utilities	Heather Rosentrater	Negative	
1	Balancing Authority of Northern California	Kevin Smith	Affirmative	
1	Baltimore Gas & Electric Company	Christopher J Scanlon	Abstain	
1	BC Hydro and Power Authority	Patricia Robertson	Abstain	
1	Beaches Energy Services	Don Cuevas	Affirmative	
1	Black Hills Corp	Wes Wingen	Affirmative	
1	Bonneville Power Administration	Donald S. Watkins	Affirmative	
1	Bryan Texas Utilities	John C Fontenot	Affirmative	
1	CenterPoint Energy Houston Electric, LLC	John Brockhan	Affirmative	
1	Central Electric Power Cooperative	Michael B Bax	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Central Iowa Power Cooperative	Kevin J Lyons		
1	Central Maine Power Company	Joseph Turano Jr.	Abstain	
1	City of Tallahassee	Daniel S Langston	Affirmative	
1	Clark Public Utilities	Jack Stamper	Affirmative	
1	Cleco Corporation	John Lindsey		
1	Colorado Springs Utilities	Shawna Speer	Affirmative	
1	Consolidated Edison Co. of New York	Christopher L de Graffenried	Affirmative	
1	Dairyland Power Coop.	Robert W. Roddy	Affirmative	
1	Dominion Virginia Power	Larry Nash	Affirmative	
1	Duke Energy Carolina	Doug E Hils	Affirmative	
1	Encari	Steven E Hamburg		
1	Entergy Transmission	Oliver A Burke	Affirmative	
1	FirstEnergy Corp.	William J Smith	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Florida Keys Electric Cooperative Assoc.	Dennis Minton	Affirmative	
1	Florida Power & Light Co.	Mike O'Neil	Affirmative	
1	Gainesville Regional Utilities	Richard Bachmeier		
1	Great River Energy	Gordon Pietsch	Affirmative	
1	Hydro One Networks, Inc.	Muhammed Ali	Affirmative	
1	Hydro-Quebec TransEnergie	Martin Boisvert	Negative	
1	Idaho Power Company	Molly Devine	Affirmative	
1	International Transmission Company Holdings Corp	Michael Moltane	Abstain	
1	JDRJC Associates	Jim D Cyrulewski	Abstain	
1	JEA	Ted E Hobson	Affirmative	
1	KAMO Electric Cooperative	Walter Kenyon	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Kansas City Power & Light Co.	Daniel Gibson	Negative	
1	Lakeland Electric	Larry E Watt		

1	Lincoln Electric System	Doug Bantam	Affirmative	
1	Long Island Power Authority	Robert Ganley	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Los Angeles Department of Water & Power	faranak sarbaz	Affirmative	
1	Lower Colorado River Authority	Martyn Turner		
1	M & A Electric Power Cooperative	William Price	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Manitoba Hydro	Jo-Anne M Ross	Affirmative	
1	MEAG Power	Danny Dees	Affirmative	
1	MidAmerican Energy Co.	Terry Harbour	Affirmative	
1	Minnkota Power Coop. Inc.	Daniel L Inman	Affirmative	
1	Muscatine Power & Water	Andrew J Kurriger		
1	N.W. Electric Power Cooperative, Inc.	Mark Ramsey		
1	National Grid USA	Michael Jones	Affirmative	
1	NB Power Corporation	Alan MacNaughton	Abstain	
1	Nebraska Public Power District	Jamison Cawley	Negative	
1	New York Power Authority	Bruce Metruck	Affirmative	
1	Northeast Missouri Electric Power Cooperative	Kevin White	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Northeast Utilities	William Temple	Affirmative	
1	Northern Indiana Public Service Co.	Julaine Dyke	Negative	
1	Ohio Valley Electric Corp.	Scott R Cunningham	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Oklahoma Gas and Electric Co.	Terri Pyle	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Omaha Public Power District	Doug Peterchuck	Affirmative	
1	Oncor Electric Delivery	Jen Fiegel	Affirmative	
1	Otter Tail Power Company	Daryl Hanson		
1	Peak Reliability	Jared Shakespeare	Affirmative	
1	Platte River Power Authority	John C. Collins	Affirmative	
1	Portland General Electric Co.	John T Walker	Affirmative	
1	Potomac Electric Power Co.	David Thorne	Negative	SUPPORTS THIRD PARTY COMMENTS
1	PPL Electric Utilities Corp.	Brenda L Truhe	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Public Service Company of New Mexico	Laurie Williams		
1	Public Service Electric and Gas Co.	Kenneth D. Brown	Negative	SUPPORTS THIRD PARTY COMMENTS - I adopt the comments of the ISO/RTO Council's Standards Review Committee
1	Puget Sound Energy, Inc.	Denise M Lietz	Negative	COMMENT RECEIVED
1	Rochester Gas and Electric Corp.	John C. Allen	Affirmative	
1	Sacramento Municipal Utility District	Tim Kelley	Affirmative	
1	Salt River Project	Robert Kondziolka		
1	SaskPower	Wayne Guttormson	Abstain	
1	Seattle City Light	Pawel Krupa	Affirmative	
1	Seminole Electric Cooperative, Inc.	Glenn Spurlock	Affirmative	
1	Snohomish County PUD No. 1	Long T Duong	Affirmative	
1	South Carolina Electric & Gas Co.	Tom Hanzlik	Affirmative	
1	South Carolina Public Service Authority	Shawn T Abrams	Abstain	
1	Southern California Edison Company	Steven Mavis	Affirmative	

1	Southern Company Services, Inc.	Robert A. Schaffeld	Negative	SUPPORTS THIRD PARTY COMMENTS
1	Southern Illinois Power Coop.	William Hutchison		
1	Southern Indiana Gas and Electric Co.	Lynnae Wilson	Affirmative	
1	Southwest Transmission Cooperative, Inc.	John Shaver	Negative	
1	Sunflower Electric Power Corporation	Noman Lee Williams		
1	Tacoma Power	John Merrell	Affirmative	
1	Tampa Electric Co.	Beth Young		
1	Tennessee Valley Authority	Howell D Scott	Negative	COMMENT RECEIVED
1	Trans Bay Cable LLC	Steven Powell		
1	Tri-State Generation & Transmission Association, Inc.	Tracy Sliman	Negative	
1	U.S. Bureau of Reclamation	Richard T Jackson		
1	United Illuminating Co.	Jonathan Appelbaum	Affirmative	
1	Westar Energy	Allen Klassen		
1	Western Area Power Administration	Lloyd A Linke	Affirmative	
1	Wind Energy Transmission Texas, LLC	Julius Horvath	Affirmative	
1	Wolverine Power Supply Coop., Inc.	Michelle Clements	Abstain	
1	Xcel Energy, Inc.	Gregory L Pieper	Affirmative	
2	BC Hydro	Venkataramakrishnan Vinnakota	Abstain	
2	California ISO	Rich Vine	Affirmative	
2	Electric Reliability Council of Texas, Inc.	Cheryl Moseley	Affirmative	
2	Independent Electricity System Operator	Leonard Kula	Affirmative	
2	ISO New England, Inc.	Matthew F Goldberg	Affirmative	
2	MISO	Marie Knox	Abstain	
2	New York Independent System Operator	Gregory Campoli	Negative	SUPPORTS THIRD PARTY COMMENTS
2	PJM Interconnection, L.L.C.	stephanie monzon	Negative	
2	Southwest Power Pool, Inc.	Charles H. Yeung	Negative	COMMENT RECEIVED
3	AEP	Michael E Deloach	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Alabama Power Company	Robert S Moore	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Ameren Corp.	David J Jendras	Abstain	
3	APS	Sarah Kist	Affirmative	
3	Associated Electric Cooperative, Inc.	Todd Bennett	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Atlantic City Electric Company	NICOLE BUCKMAN	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Avista Corp.	Scott J Kinney	Negative	
3	BC Hydro and Power Authority	Pat G. Harrington	Abstain	
3	Bonneville Power Administration	Rebecca Berdahl	Affirmative	
3	Central Electric Power Cooperative	Adam M Weber	Negative	SUPPORTS THIRD PARTY COMMENTS
3	City of Austin dba Austin Energy	Andrew Gallo	Affirmative	
3	City of Bartow, Florida	Matt Culverhouse	Affirmative	
3	City of Clewiston	Lynne Mila	Affirmative	
3	City of Farmington	Linda R Jacobson	Abstain	
3	City of Garland	Ronnie C Hoeinghaus	Abstain	
3	City of Green Cove Springs	Mark Schultz	Affirmative	
3	City of Homestead	Orestes J Garcia	Affirmative	
3	City of Redding	Bill Hughes	Affirmative	
3	City of Tallahassee	Bill R Fowler	Affirmative	
3	City of Vineland	Kathy Caignon		
3	Cleco Corporation	Michelle A Corley		

3	Colorado Springs Utilities	Jean Mueller	Affirmative	
3	ComEd	John Bee	Abstain	
3	Consolidated Edison Co. of New York	Peter T Yost	Affirmative	
3	Consumers Energy Company	Gerald G Farringer	Affirmative	
3	Cowlitz County PUD	Russell A Noble	Affirmative	
3	Delmarva Power & Light Co.	Michael R. Mayer	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Dominion Resources, Inc.	Connie B Lowe	Affirmative	
3	DTE Electric	Kent Kujala	Affirmative	
3	FirstEnergy Corp.	Cindy E Stewart	Negative	SUPPORTS THIRD PARTY COMMENTS - RSC Comments
3	Florida Keys Electric Cooperative	Tom B Anthony		
3	Florida Municipal Power Agency	Joe McKinney	Affirmative	
3	Florida Power & Light Co.	Summer C. Esquerre		
3	Florida Power Corporation	Lee Schuster	Affirmative	
3	Gainesville Regional Utilities	Kenneth Simmons	Affirmative	
3	Georgia System Operations Corporation	Scott McGough	Negative	
3	Great River Energy	Brian Glover		
3	Hydro One Networks, Inc.	Ayesha Sabouba	Affirmative	
3	JEA	Garry Baker		
3	KAMO Electric Cooperative	Theodore J Hilmes	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Kansas City Power & Light Co.	Joshua D Bach	Negative	
3	Kissimmee Utility Authority	Gregory D Woessner	Affirmative	
3	Lakeland Electric	Mace D Hunter	Affirmative	
3	Lincoln Electric System	Jason Fortik	Affirmative	
3	Los Angeles Department of Water & Power	Mike Anctil	Affirmative	
3	Louisville Gas and Electric Co.	Charles A. Freibert	Negative	
3	M & A Electric Power Cooperative	Stephen D Pogue	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Manitoba Hydro	Greg C. Parent	Affirmative	
3	MEAG Power	Roger Brand	Affirmative	
3	MidAmerican Energy Co.	Thomas C. Mielnik	Affirmative	
3	Modesto Irrigation District	Jack W Savage	Affirmative	
3	Muscatine Power & Water	Jenn Stover	Affirmative	
3	National Grid USA	Brian E Shanahan	Affirmative	
3	Nebraska Public Power District	Tony Eddleman	Negative	SUPPORTS THIRD PARTY COMMENTS
3	New York Power Authority	David R Rivera	Affirmative	
3	Northern Indiana Public Service Co.	Ramon J Barany	Affirmative	
3	NW Electric Power Cooperative, Inc.	David McDowell		
3	Ocala Utility Services	Randy Hahn	Affirmative	
3	Oklahoma Gas and Electric Co.	Donald Hargrove	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Orlando Utilities Commission	Ballard K Mutters	Affirmative	
3	Owensboro Municipal Utilities	Thomas T Lyons	Affirmative	
3	Pacific Gas and Electric Company	John H Hagen	Affirmative	
3	Platte River Power Authority	Terry L Baker	Affirmative	
3	Portland General Electric Co.	Thomas G Ward	Affirmative	
3	Potomac Electric Power Co.	Mark Yerger	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Public Service Electric and Gas Co.	Jeffrey Mueller	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Puget Sound Energy, Inc.	Mariah R Kennedy	Negative	COMMENT

				RECEIVED
3	Sacramento Municipal Utility District	James Leigh-Kendall	Affirmative	
3	Salt River Project	John T. Underhill	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Santee Cooper	James M Poston	Abstain	
3	Seattle City Light	Dana Wheelock	Affirmative	
3	Seminole Electric Cooperative, Inc.	James R Frauen	Affirmative	
3	Sho-Me Power Electric Cooperative	Jeff L Neas	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Snohomish County PUD No. 1	Mark Oens	Affirmative	
3	South Carolina Electric & Gas Co.	Hubert C Young	Affirmative	
3	Southern California Edison Company	Lujuanna Medina	Affirmative	
3	Southern Indiana Gas and Electric Co.	Fred Frederick	Affirmative	
3	Tacoma Power	Marc Donaldson	Affirmative	
3	Tampa Electric Co.	Ronald L. Donahey		
3	Tennessee Valley Authority	Ian S Grant		
3	Tri-State Generation & Transmission Association, Inc.	Janelle Marriott	Negative	
3	Westar Energy	Bo Jones	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Wisconsin Electric Power Marketing	James R Keller	Negative	SUPPORTS THIRD PARTY COMMENTS
3	Xcel Energy, Inc.	Michael Ibold	Affirmative	
4	Alliant Energy Corp. Services, Inc.	Kenneth Goldsmith	Affirmative	
4	Blue Ridge Power Agency	Duane S Dahlquist	Affirmative	
4	City of Austin dba Austin Energy	Reza Ebrahimian	Affirmative	
4	City of New Smyrna Beach Utilities Commission	Tim Beyrle	Affirmative	
4	City of Redding	Nicholas Zettel	Affirmative	
4	City Utilities of Springfield, Missouri	John Allen	Affirmative	
4	Consumers Energy Company	Tracy Goble	Affirmative	
4	Cowlitz County PUD	Rick Syring	Affirmative	
4	DTE Electric	Daniel Herring	Affirmative	
4	Flathead Electric Cooperative	Russ Schneider	Negative	
4	Florida Municipal Power Agency	Carol Chinn	Affirmative	
4	Georgia System Operations Corporation	Guy Andrews	Negative	
4	Herb Schrayshuen	Herb Schrayshuen	Affirmative	
4	Illinois Municipal Electric Agency	Bob C. Thomas	Affirmative	
4	Indiana Municipal Power Agency	Jack Alvey	Abstain	
4	Madison Gas and Electric Co.	Joseph DePoorter	Affirmative	
4	Modesto Irrigation District	Spencer Tacke		
4	Ohio Edison Company	Douglas Hohlbaugh		
4	Oklahoma Municipal Power Authority	Ashley Stringer	Affirmative	
4	Old Dominion Electric Coop.	Mark Ringhausen	Negative	SUPPORTS THIRD PARTY COMMENTS
4	Public Utility District No. 1 of Snohomish County	John D Martinsen	Affirmative	
4	Sacramento Municipal Utility District	Mike Ramirez	Affirmative	
4	Seattle City Light	Hao Li	Affirmative	
4	Seminole Electric Cooperative, Inc.	Steven R Wallace	Affirmative	
4	South Mississippi Electric Power Association	Steve McElhaney		
4	Tacoma Public Utilities	Keith Morisette	Affirmative	
4	Utility Services, Inc.	Brian Evans-Mongeon	Abstain	
4	Wisconsin Energy Corp.	Anthony P Jankowski	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Amerenue	Sam Dwyer		
5	American Electric Power	Thomas Foltz	Negative	COMMENT RECEIVED
5	Arizona Public Service Co.	Scott Takinen	Affirmative	

5	Associated Electric Cooperative, Inc.	Matthew Pacobit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Avista Corp.	Steve Wenke		
5	BC Hydro and Power Authority	Clement Ma	Abstain	
5	Black Hills Corp	George Tatar	Abstain	
5	Bonneville Power Administration	Francis J. Halpin	Affirmative	
5	Brazos Electric Power Cooperative, Inc.	Shari Heino	Negative	SUPPORTS THIRD PARTY COMMENTS
5	City and County of San Francisco	Daniel Mason	Affirmative	
5	City of Austin dba Austin Energy	Jeanie Doty	Affirmative	
5	City of Redding	Paul A. Cummings	Affirmative	
5	City of Tallahassee	Karen Webb	Affirmative	
5	City Water, Light & Power of Springfield	Steve Rose	Affirmative	
5	Cleco Power	Stephanie Huffman		
5	Colorado Springs Utilities	Kaleb Brimhall	Affirmative	
5	Con Edison Company of New York	Brian O'Boyle	Affirmative	
5	Consumers Energy Company	David C Greyerbiehl	Affirmative	
5	Cowlitz County PUD	Bob Essex	Affirmative	
5	Dominion Resources, Inc.	Mike Garton	Affirmative	
5	DTE Electric	Mark Stefaniak	Affirmative	
5	Duke Energy	Dale Q Goodwine	Affirmative	
5	Dynegy Inc.	Dan Roethemeyer	Affirmative	
5	E.ON Climate & Renewables North America, LLC	Dana Showalter		
5	Entergy Services, Inc.	Tracey Stubbs	Affirmative	
5	Exelon Nuclear	Mark F Draper	Affirmative	
5	First Wind	John Robertson	Abstain	
5	FirstEnergy Solutions	Kenneth Dresner	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Florida Municipal Power Agency	David Schumann	Affirmative	
5	Great River Energy	Preston L Walsh	Affirmative	
5	Independence Power & Light Dept.	James Nail	Affirmative	
5	JEA	John J Babik	Affirmative	
5	Kansas City Power & Light Co.	Brett Holland	Negative	
5	Kissimmee Utility Authority	Mike Blough	Affirmative	
5	Lakeland Electric	James M Howard		
5	Liberty Electric Power LLC	Daniel Duff		
5	Lincoln Electric System	Dennis Florom	Affirmative	
5	Los Angeles Department of Water & Power	Kenneth Silver	Affirmative	
5	Lower Colorado River Authority	Dixie Wells	Affirmative	
5	Luminant Generation Company LLC	Rick Terrill	Affirmative	
5	Manitoba Hydro	Yuguang Xiao	Affirmative	
5	Massachusetts Municipal Wholesale Electric Company	David Gordon	Abstain	
5	MEAG Power	Steven Grego	Affirmative	
5	Muscatine Power & Water	Mike Avesing	Affirmative	
5	Nebraska Public Power District	Don Schmit	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Nevada Power Co.	Richard Salgo	Affirmative	
5	New York Power Authority	Wayne Sipperly	Affirmative	
5	NextEra Energy	Allen D Schriver	Affirmative	
5	Northern Indiana Public Service Co.	Michael D Melvin	Negative	
5	Oglethorpe Power Corporation	Bernard Johnson	Negative	
5	Oklahoma Gas and Electric Co.	Henry L Staples	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Omaha Public Power District	Mahmood Z. Safi	Affirmative	
5	Pacific Gas and Electric Company	Alex Chua		
5	Platte River Power Authority	Christopher R Wood	Affirmative	
5	Portland General Electric Co.	Matt E. Jastram	Affirmative	
				SUPPORTS

5	PPL Generation LLC	Annette M Bannon	Negative	THIRD PARTY COMMENTS
5	PSEG Fossil LLC	Tim Kucey	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Public Utility District No. 2 of Grant County, Washington	Michiko Sell		
5	Puget Sound Energy, Inc.	Lynda Kupfer	Negative	
5	Sacramento Municipal Utility District	Susan Gill-Zobitz	Affirmative	
5	Salt River Project	William Alkema	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Santee Cooper	Lewis P Pierce	Abstain	
5	Seattle City Light	Michael J. Haynes	Affirmative	
5	Seminole Electric Cooperative, Inc.	Brenda K. Atkins	Affirmative	
5	Snohomish County PUD No. 1	Sam Nietfeld	Affirmative	
5	South Carolina Electric & Gas Co.	Edward Magic	Affirmative	
5	Southern California Edison Company	Denise Yaffe	Affirmative	
5	Southern Company Generation	William D Shultz	Negative	
5	Southern Indiana Gas and Electric Co.	Rob Collins	Affirmative	
5	Tacoma Power	Chris Mattson	Affirmative	
5	Tampa Electric Co.	RJames Rocha	Affirmative	
5	Tri-State Generation & Transmission Association, Inc.	Mark Stein		
5	TVA Power System Operations (PSO)	Brandy B Spraker	Negative	COMMENT RECEIVED
5	U.S. Army Corps of Engineers	Melissa Kurtz	Abstain	
5	USDI Bureau of Reclamation	Erika Doot		
5	Westar Energy	Bryan Taggart	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Wisconsin Electric Power Co.	Linda Horn	Negative	SUPPORTS THIRD PARTY COMMENTS
5	Xcel Energy, Inc.	Mark A Castagneri	Affirmative	
6	AEP Marketing	Edward P. Cox		
6	Ameren Missouri	Robert Quinlivan	Abstain	
6	APS	Randy A. Young	Affirmative	
6	Associated Electric Cooperative, Inc.	Brian Ackermann	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Bonneville Power Administration	Brenda S. Anderson	Affirmative	
6	City of Austin dba Austin Energy	Lisa Martin	Affirmative	
6	City of Redding	Marvin Briggs	Affirmative	
6	Cleco Power LLC	Robert Hirchak		
6	Colorado Springs Utilities	Shannon Fair	Affirmative	
6	Con Edison Company of New York	David Balban	Affirmative	
6	Constellation Energy Commodities Group	David J Carlson	Abstain	
6	Dominion Resources, Inc.	Louis S. Slade	Affirmative	
6	Duke Energy	Greg Cecil	Negative	SUPPORTS THIRD PARTY COMMENTS
6	FirstEnergy Solutions	Kevin Querry	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Florida Municipal Power Agency	Richard L. Montgomery	Affirmative	
6	Florida Municipal Power Pool	Thomas Reedy	Affirmative	
6	Florida Power & Light Co.	Silvia P Mitchell	Affirmative	
6	Kansas City Power & Light Co.	Jessica L Klinghoffer	Negative	COMMENT RECEIVED
6	Lakeland Electric	Paul Shipps	Abstain	
6	Lincoln Electric System	Eric Ruskamp	Affirmative	
6	Los Angeles Department of Water & Power	Brad Packer	Affirmative	
6	Lower Colorado River Authority	Michael Shaw	Negative	

6	Luminant Energy	Brenda Hampton		
6	Manitoba Hydro	Blair Mukanik	Affirmative	
6	Modesto Irrigation District	James McFall	Affirmative	
6	Muscatine Power & Water	John Stolley	Affirmative	
6	New York Power Authority	Shivaz Chopra	Affirmative	
6	Northern Indiana Public Service Co.	Joseph O'Brien	Affirmative	
6	Oglethorpe Power Corporation	Donna Johnson	Negative	
6	Oklahoma Gas and Electric Co.	Jerry Nottnagel	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Omaha Public Power District	Douglas Collins		
6	PacifiCorp	Sandra L Shaffer	Affirmative	
6	Platte River Power Authority	Carol Ballantine	Affirmative	
6	Portland General Electric Co.	Shawn P Davis	Affirmative	
6	PPL EnergyPlus LLC	Elizabeth Davis	Negative	
6	PSEG Energy Resources & Trade LLC	Peter Dolan	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Sacramento Municipal Utility District	Diane Enderby	Affirmative	
6	Salt River Project	William Abraham	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Santee Cooper	Michael Brown	Abstain	
6	Seattle City Light	Dennis Sismaet	Affirmative	
6	Seminole Electric Cooperative, Inc.	Trudy S. Novak	Affirmative	
6	Snohomish County PUD No. 1	Kenn Backholm	Affirmative	
6	South Carolina Electric & Gas Co.	Matt H Bullard		
6	Southern California Edison Company	Joseph T Marone	Affirmative	
6	Southern Company Generation and Energy Marketing	John J. Ciza	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Southern Indiana Gas and Electric Co.	Brad Lisembee	Affirmative	
6	Tacoma Public Utilities	Michael C Hill	Affirmative	
6	Tampa Electric Co.	Benjamin F Smith II	Affirmative	
6	Tennessee Valley Authority	Marjorie S Parsons	Negative	
6	Westar Energy	Grant L Wilkerson	Negative	SUPPORTS THIRD PARTY COMMENTS
6	Western Area Power Administration - UGP Marketing	Mark Messerli	Affirmative	
6	Xcel Energy, Inc.	Peter Colussy	Affirmative	
7	Brickfield, Burchette, Ritts & Stone, P.C.	Thomas W Siegrist	Affirmative	
7	Luminant Mining Company LLC	Stewart Rake		
8		Roger C Zaklukiewicz	Affirmative	
8		David L Kiguel	Affirmative	
8	Foundation for Resilient Societies	William R Harris		
8	Massachusetts Attorney General	Frederick R Plett	Affirmative	
8	Volkmann Consulting, Inc.	Terry Volkmann	Affirmative	
9	Commonwealth of Massachusetts Department of Public Utilities	Donald Nelson	Affirmative	
9	New York State Public Service Commission	Diane J Barney	Affirmative	
10	Florida Reliability Coordinating Council	Linda C Campbell	Affirmative	
10	Midwest Reliability Organization	Russel Mountjoy	Affirmative	
10	New York State Reliability Council	Alan Adamson	Affirmative	
10	Northeast Power Coordinating Council	Guy V. Zito	Affirmative	
10	ReliabilityFirst	Anthony E Jablonski	Negative	COMMENT RECEIVED
10	SERC Reliability Corporation	Joseph W Spencer	Affirmative	
10	Texas Reliability Entity, Inc.	Karin Schweitzer	Negative	COMMENT RECEIVED

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Washington Office: 1325 G Street, N.W. : Suite 600 : Washington, DC 20005-3801

Account Log-In/Register

Exhibit H

Standard Drafting Team Roster for Project 2009-03, Emergency Operations

Project 2009-03 Emergency Operations Standard Drafting Team

Name and Title	Company and Address	Contact Info	Bio
David McRee Chair	Duke Energy 526 South Church Street, Charlotte, NC 28202	704-382-9841 David.McRee@duke-energy.com	David McRee has worked for Duke Energy for 23 years. David has spent 20 years in the System Operations area as a system coordinator, operations engineer and is RC certified. He was recently named System Operations Supervisor in the Operating Center located in Charlotte, NC. For the past 15 years, David has served and continues to be the Subject Matter Expert for Duke on the EOP standards and coordinates the Emergency Capacity and Restoration Plans at Duke. David has worked with the Balancing Authority Reliability-based Control Standard Drafting Team on the new BAL Standards and is participating on the Interchange Standard Drafting team.
Robert Staton Vice Chair	Xcel Energy 18201 West 10th Avenue, Golden, CO 80401	303-273-4797 robert.staton@xcelenergy.com	Bob Staton has 30 years of experience in system operations; including transmission, distribution, generations, balancing, and marketing. He was a RC shift manager for MISO during the startup of the RC and market functions, and is currently the transmission and generation control center manager for Public Service Company of Colorado. Most of his career was spent working for Northern States Power in Minneapolis as an operator, director of marketing, and manager of the Minnesota and Wisconsin transmission control centers.
Will Behnke	Alliance Energy 4902 North Biltmore Lane, Madison, WI 53718	608-458-8206 WillBehnke@alliantenergy.com	Will Behnke has worked in utility operations field for 40 years; participated in restoration of Emergency response situations, specifically the 2007 Iowa Ice Storm; Chair of MISO Emergency Preparedness/Power System Restoration Working Group and Vice Chair of the MISO System Operators Training Working Group. Will was involved in the complete construction and

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			startup of a 385 MW coal fired unit, Operated the WPL transmission system, implemented switching agreements and has worked in Compliance for the last 6 years.
Richard Cobb	Midwest ISO 2985 Ames Crossing Road, Eagan, MN 55121-2498	651-632-8468 rcobb@misoenergy.org	Richard Cobb has thirty-four-and-a-half years in the electric industry, starting with operating power plants, currently function as a Senior Trainer for MISO; training operations personnel on Reliability Coordination, Balancing Authority and Market Operations functions, etc. Senior Reliability Coordinator for both MAPP and MISO. Coordinate PSR drills with MISO annually. Currently NERC RC Certified and also a member (vice chair) of the MRO's SMET on PER-005.
Jen Fiegel	Oncor Electric Delivery 2233-C Mountain Creek Parkway, Dallas, TX 75211	214-743-6825 Jfiegel1@oncor.com	Jen Fiegel is the Senior Director Risk Management responsible for oversight and governance for Oncor's Reliability Standards, Environmental and Risk Management programs. Provides strategic leadership through partnering with multiple business units across the organization and externally with regulatory entities including FERC, NERC and Texas Reliability Entity. Worked assignments in NERC Compliance, Transmission Construction and Transmission Program Management Office (PMO) for Competitive Renewable Energy Zone (CREZ). Alumnus of Oncor's Leadership Development Program. Bachelor of Science in Management Science from Geneseo State University. Current chair of the North American Transmission Forum (NATF) Internal Controls Working Group, chair of the ERCOT NERC Reliability Working Group and serves on the Edison Electric Institute (EEI) Reliability Executive Advisory Committee. Active participant in multiple national and regional committees and working groups in the industry.

Name and Title	Company and Address	Contact Info	Bio
Francis Halpin	Bonneville Power Administration 905 NE 11th Avenue PGSD-5, Portland, OR 97232	503-230-7545 fjhalpin@bpa.gov	Francis Halpin has twenty years of broad power industry experience, including hydro operations, generation scheduling, interchange scheduling, power marketing, and service to load. Experience attained at Portland General Electric and the Bonneville Power Administration. Participation in numerous NERC, WECC, and NAESB committees; involved in general Emergency Planning, as well as Energy and Capacity Emergency Planning at BPA; provide technical support to BPA's Real-time generation scheduling group, planning and scheduling generation during the operational day for the Federal Columbia River Power System (22,000MW nameplate); work closely with hydro project operators and generation dispatchers during routine and emergency situations. Expertise is in Real-time Hydro Operations and Real-time Generation Scheduling. Member of the three agency (Corps, Reclamation, BPA) Reliability Implementation and Technical Subcommittee, to address issues related to reliability and standards compliance; member of a WECC drafting team for WECC-0056, which wrote modifications to INT-BPS-007-0 Near Term Emergencies; currently hold NERC System Operator certification for Reliability Coordination (RC200504144).
Hal Haugom	Madison Gas and Electric, Inc. P.O. Box 1231, Madison, WI 53701	608-252-5608 hhaugom@mge.com	Hal Haugom has over 30 years of experience in System Operations. Responsible for Emergency Operations at MGE and work with ATC on System Restoration Procedures.
Gregory LeGrave	Wisconsin Public Service Corp. 2830 S. Ashland Ave. Green Bay, WI 54304	920-617-4119 GJLEGrave@Wisconsinpublicservice.com	Greg LeGrave has been employed with Wisconsin Public Service for over 25 years. Greg has worked in various capacities, including Regional Engineer, Meter Supervisor, Customer Service Manager, Director of Distrbution Planning, for the past six years as the Manager of System Operating and Dispatch. Greg is an active member of the MISO Operations Working Group and Reliability

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			Subcommittee and chairs the MISO Balancing Authority Task Team. Greg was also the inaugural Chair of the Electric Reliability Subcommittee for the Midwest Energy Association.
Steve Lesiuta	Ontario Power Generation 800 Kipling Avenue KR 303 Toronto, Ontario, Canada M8Z 5S4	416-231-4111, ext. 4034 Steve.lesiuta@opg.com	Steve Lesiuta is the Manager, Emergency Management Programming since 2007. Responsibilities include: Ensuring OPG fulfills all compliance and IESO Market Rule requirements related to emergency planning, member of the IESO-led Crisis Management Support Team, annual preparation and review of the OPG Emergency Preparedness and Response Plan, review and update of Restoration Participation Attachments for each plan, manage OPG Crisis Management and Communication Center, including leading and developing exercises, OPG lead on IESO review of Ontario Power System Restoration Plan, and led OPGs involvement with restoration exercises and workshops.
Connie Lowe	Dominion Resources Services, Inc. 120 Tredegar Street, Richmond, VA 23219	804-819-2917, tie line 8-738-2917 Connie.Lowe@dom.com	Connie Lowe has is a twenty-five year employee of Dominion; Distribution Dispatching, Regional Operations Center, System Operations Center (SOC), Market Operations Center (MOC) and Corporate NERC Compliance group; 0SOC NERC Tagging Specialist, NERC Certified Operator, Generation Dispatcher when Dominion was RC, BA, TOP, etc., prior to joining PJM in 2007. MOC Coordination of Dominion's new MOC when joining PJM; creating many interal routine and emergency procedures for Generation Dispatchers and worked with Dominion's GO/GOP/TO/DP/LCC to create additional routine/emergency coordinated procedures. Market Operator/Generation Dispatcher, Training Coordinator - NERC CEH Provider; created in-house CEH classes for Generation Dispatchers on System Restoration, Back-up Control Center and Satellite phones. Responsible for MOC PSE procedures and compliance, new generator coordination with

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			GO, GOP, PJM, SOC & Energy Management System (EMS) Engineering Staff, Project Manager - new Back-up Control Center for the MOC. Member of PJM committees and subcommittees dealing with System Operator Training, Outage Reporting, Black Start and System Restoration. NERC Compliance Manager; created NERC Standard Guidelines for our Registered Entities (GO, GOP, DP, TO, PSE, LSE), registered in SERC, RFC, NPCC and RFC Monitor, comment and vote on applicable Standards Under Development, NERC Balloting Member, Audit support; RSAW review prior to audits.
Brad Young	LG&E and KU Services Company Room 357 1 Quality Street Lexington, KY 40507	859-367-5703 Brad.young@lge-ku.com	Brad Young is currently the Manager of Transmission Reliability/Compliance for LG&E and KU Services Company (a subsidiary of PPL) in Louisville, KY. Employed by Louisville Gas & Electric (LG&E) or Kentucky Utilities (KU) Companies for 31 years, holding current position for five years. Served on the NERC Severe Impact Resilience Task Force (SIRTF) and the Geomagnetic Disturbance Task Force (GMDTF) Phase 1 & 2, and has participated on various SERC Compliance Audits as an Industry subject matter expert. Served a total of 17 years in Transmission System Operations, 9 years as the Manager of Transmission System Operations for both LG&E and KU, and 7 years as the Manager of KU Transmission System Control Centers. Representative on various ECAR, RFC, and SERC Operating & Reliability Committees. Nine years of experience as an electrical engineer and supervisor in the KU Transmission System Planning Department, being a member of the ECAR Transmission System Performance Panel & Liaison. Eight years on active duty in the United States Air Force and retired from the Air Force Reserves in 2011 with nearly 38 total years of commissioned military service. KC-135 tanker pilot, a maintenance and logistics officer, and achieved the rank of a two star Major General. Possessed a NERC Certified Operator Certificate

Name and Title	Company and Address	Contact Info	Bio
			at the Reliability Coordinator level from 1999 until 2004 and is a Senior Member of the IEEE.
Laura Anderson Standards Developer	North American Electric Reliability Corporation 3353 Peachtree Road, NE, Suite 600 - North Tower Atlanta, GA 30326	404-446-9671 laura.anderson@nerc.net	Laura Anderson is the lead NERC Staff for Project 2009-03, Emergency Operations. Laura began her career with NERC in January 2012. Laura also was the lead NERC Staff for the Five-Year Review Team of Project 2009-03 Emergency Operations. Prior to joining NERC, Laura was the Program Coordinator at Duke University where she managed post-graduate medical education events in various national venues for world-class surgeons in the field of laparoscopic surgery. Her experience prior to Duke University was in the legal field, where she produced official records for state and federal courts for twelve years.
Stephen Crutchfield Standards Developer	North American Electric Reliability Corporation 3353 Peachtree Road, NE, Suite 600 - North Tower Atlanta, GA 30326	609-651-9455 Stephen.crutchfield@nerc.net	Stephen Crutchfield is the supporting NERC Staff Coordinator for Project 2009-03, Emergency Operations. Stephen began his career with NERC in May 2007. Prior to joining NERC, Stephen was a Project Manager with Shaw Energy Delivery Services, managing engineering and construction projects in the substation and transmission line fields. Stephen's background also includes experience with PJM as Manager of RTO Integration, working on the operations and markets integration of new members (AEP, ComEd, Dayton, Dominion and Duquesne) into PJM and southern seams operations issues with Progress Energy, Duke and TVA. Stephen also helped lead the team that was developing GridSouth in the dual roles of Organization Architect and Manager of Customer Support. Prior to GridSouth, Stephen was the Manager of Power System Operations Training at Progress Energy where he spent over 10 years training System Operators and Engineers. Overall, Stephen was with Progress Energy for 16 years.